



United Energy Demand Response Project Performance Report - Milestone 2

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1. Summary

This document is the United Energy (UE) Demand Response Project Performance Report for the ARENA Advancing Renewables Programme – Demand Response programme (RB006). It fulfils an obligation under the Knowledge Sharing Plan to provide an update on the status of the delivery of the project including sharing of results and lessons learnt.

This report documents the major achievements of the project since the release of the last milestone report. These achievements include successful completion of:

- 1) AEMO's testing of UE's demand response reserve capability, including a baseline accuracy review;
- 2) UE's zone substation dynamic voltage management system trial; and
- 3) Quantifying the sensitivity of demand to voltage changes on UE's distribution network.

To minimise duplication of content, this report should be read as a continuation of the milestone 1 report.

The contents of this report will be presented at the upcoming ARENA workshop. UE has already commenced sharing this information with other Victorian Distribution Network Service Providers and intends to present the information contained in this report at future public events. Any parties interested in discussing the contents of this report directly with United Energy are encouraged to contact United Energy at planning@ue.com.au.



2. AEMO's testing of UE's demand response reserve capability

United Energy undertook two separate tests with AEMO.

The objectives of the first test undertaken on 1st December 2017 were to :-

1. confirm UE's demand response reserve capability achieves the required 12MW;
2. ensure the ITT (Invitation to Tender) and activation communication channels were operating correctly and acted on within the required period of time of 30 minutes and 10 minutes respectively; and
3. validate the suitability and accuracy of the default baselining methodology.

Following the first test (where we estimated that UE had delivered 19MW of demand response by way of voltage reduction), UE and AEMO agreed to undertake a second test for the following reasons:

1. The first test revealed that the default baselining methodology was unsuitable for UE's load shape with demand response numbers calculated by the AEMO baselining method significantly overestimating the level of demand response actually delivered when compared against high frequency metering over the same period; and
2. A substantial reduction in ambient temperature midway during the demand response event window resulted in a substantial reduction in electricity demand, making it difficult to determine the demand response contribution due to the voltage reduction compared to the demand response due to the substantial reduction in ambient temperature

The objectives of the second test undertaken on 16th January 2018 were to :-

1. reconfirm UE's demand response reserve capability achieves the required 12MW; and
2. validate the suitability and accuracy of the negotiated baselining methodology.

Further details on the baselining accuracy and renegotiation of the baselining method between UE and AEMO to achieve greater baselining accuracy is discussed below.

In summary, in all of the baselining methods tested, the results of the two tests have confirmed that UE has delivered at least the required 12MW of demand response capability, and that the communication process to receive and accept the ITT, and the subsequent activation of the demand response reserve capability have been successfully demonstrated.

2.1. First Test - 1st December 2017

AEMO called the first test with UE on 1st December 2017 for a 2 hour period starting 12:00 market time.

The following charts show the high frequency sampling rate measurements of the total demand included in UE's demand response portfolio, before and during the first test. Activation of the demand response by way of voltage reduction is clearly evident 10 minutes before the event start date at 12:00 market time with demand falling from 1220MW to around 1203MW.

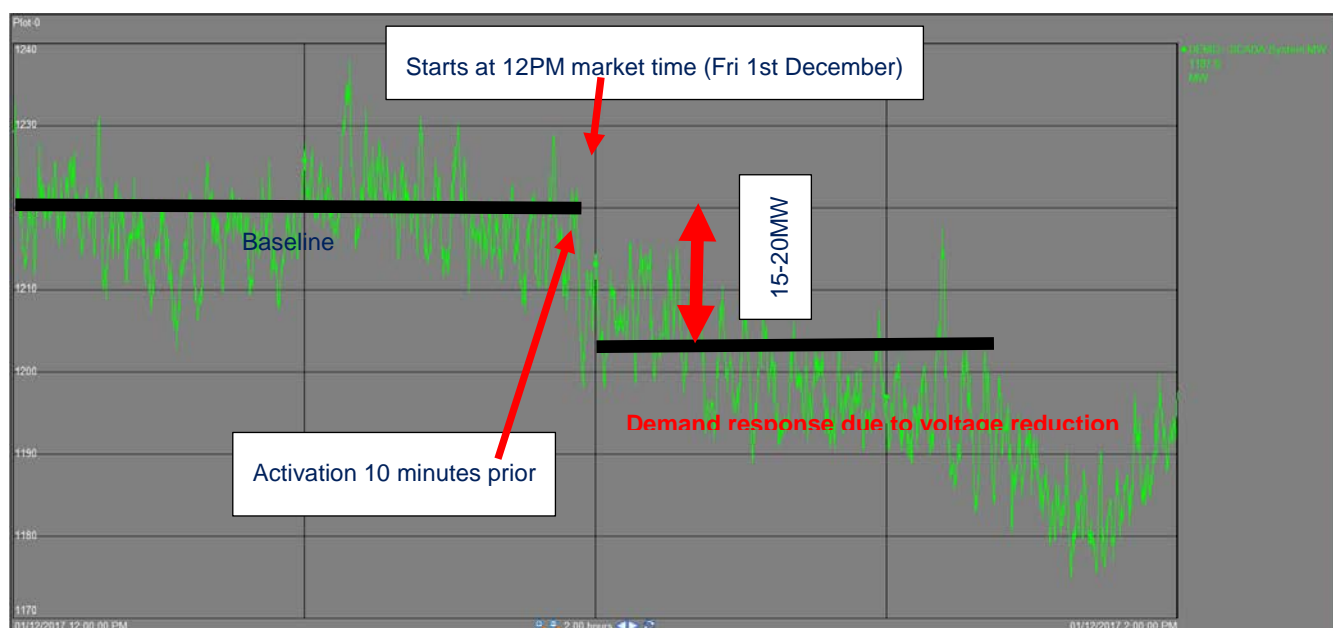


Figure 1 First hour of first test showing demand response due to voltage reduction

The demand response was held for the entire first hour, at which point demand began to fall very rapidly from around 13:10 market time. It was identified that this additional drop in demand was not triggered by the voltage reduction, but instead by a substantial fall in the ambient temperature across the UE network service area.

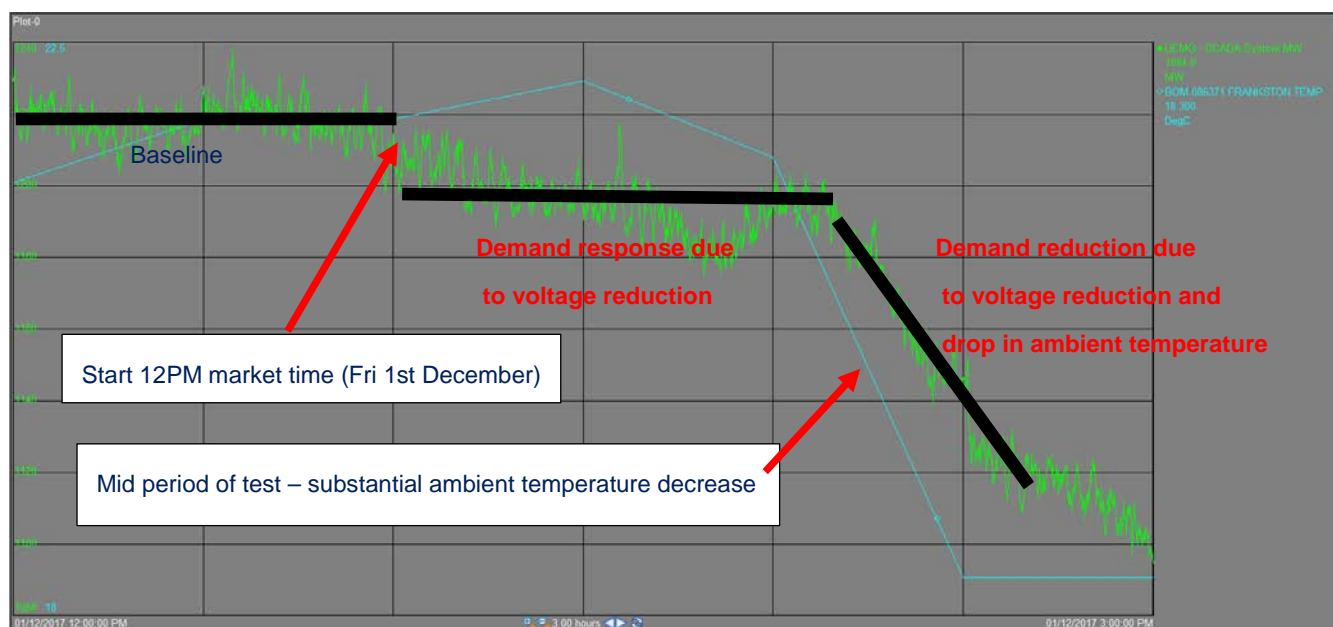


Figure 2 Second hour of first test showing demand response due to decreasing ambient temperatures

This ambient temperature externality resulted in difficulties in AEMO confirming the demand response due to voltage reduction for the entire two hour event window. It was therefore agreed with AEMO to undertake a second test under more stable temperature conditions to minimise any external factors influencing the results.

2.2. Second Test – 16th January 2018

AEMO called the second test with UE on 16th January 2018 for a 2 hour period starting 11:00 market time.

The following charts show the high frequency sampling rate measurements of the total demand included in UE's demand response portfolio, before, during and after the second test. Activation of the demand response by way of voltage reduction is clearly evident 10 minutes before the event start date at 11:00 market time with demand falling from 930MW to around 911MW. This level of demand response was held for the entire event period as shown with demand recovering after the event period once network voltage levels were returned to their normal levels.

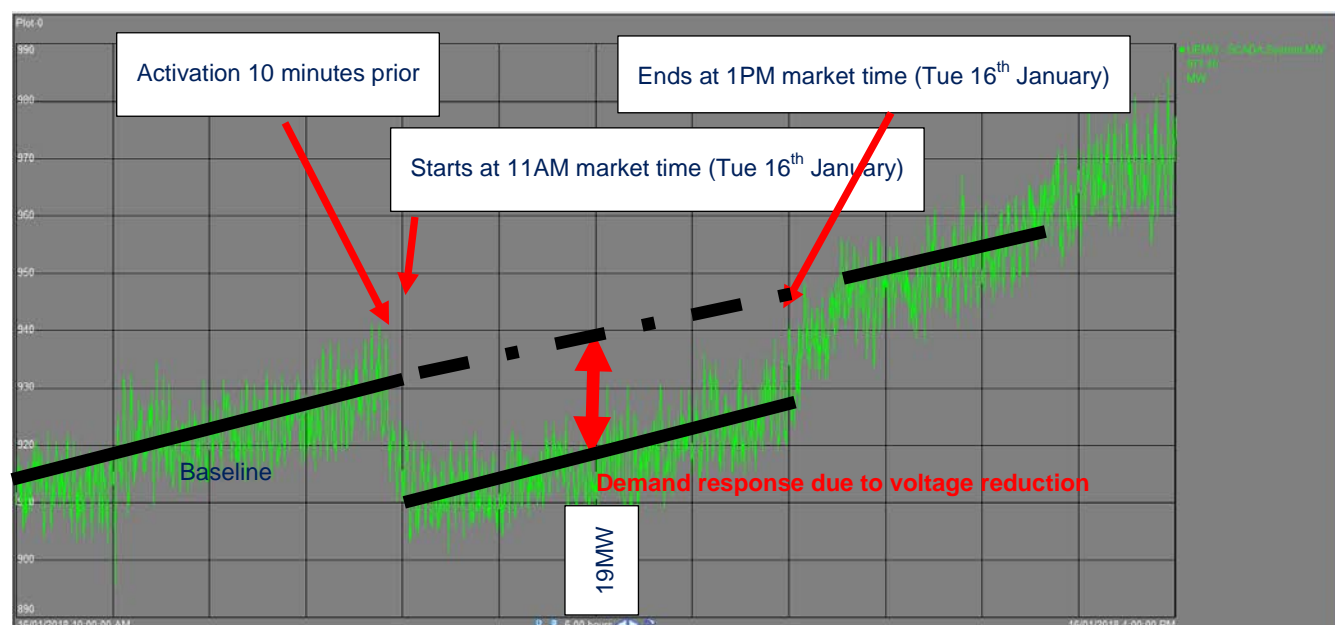


Figure 3 Second test showing demand response due to voltage reduction

The results of the AEMO assessment of this test event are summarised below.

Table 1: Assessment of Demand Response Delivered by UE (12MW required)

Half Hour Period	AEMO Default Baseline Method	UE / AEMO Renegotiated Baseline Method	UE Proposed Baseline Method	UE High Frequency Data (as above)
1	44MW	29MW	16MW	20MW
2	43MW	31MW	18MW	20MW
3	50MW	37MW	25MW	19MW
4	47MW	35MW	22MW	18MW
Average	46MW	33MW	20MW	19MW

Clearly in all baseline assessments, UE exceeded the required 12MW of demand response.



2.3. Baseline accuracy assessment and review

The assessment of the demand response delivered is highly dependent on the baseline method selected, particularly in instances where the shape of the daily demand changes from day to day. In UE's case, the major contributor to the shape of the daily demand curve is the ambient temperature. This is illustrated below and shows how the default AEMO baselining method (Method 1) is inappropriate for UE's demand curve and can result in substantial overestimation or underestimation of the demand response delivered.

How Baselining Works

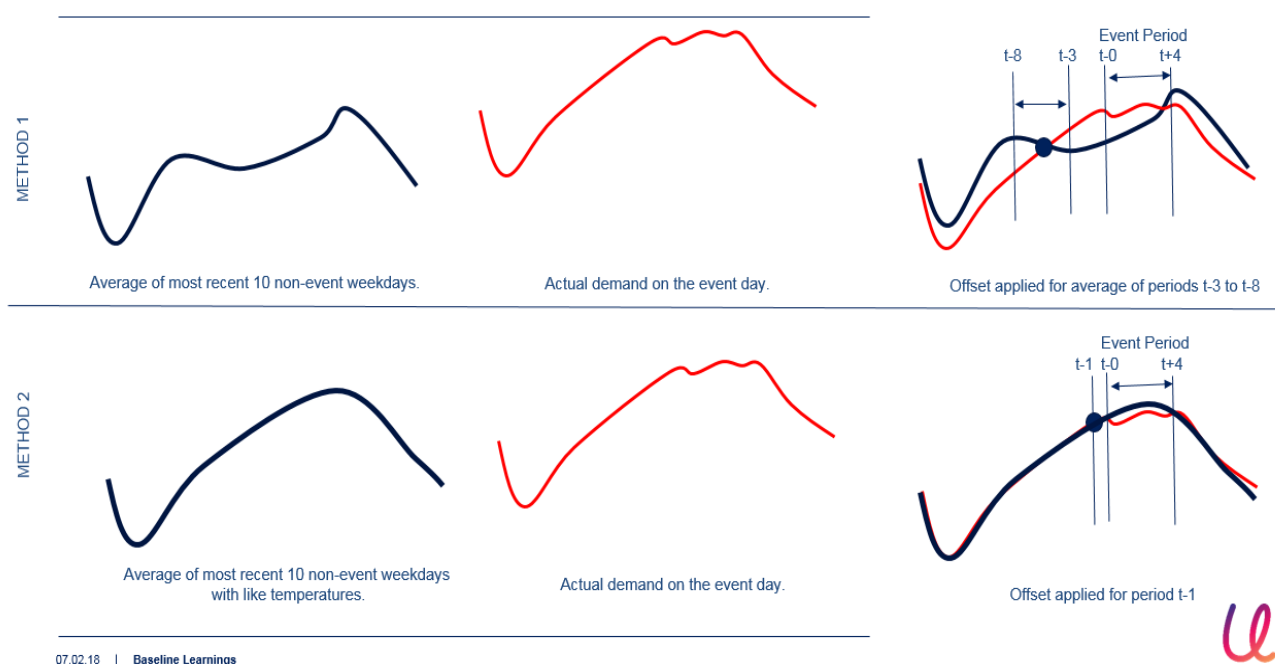


Figure 4 Suitability of Baseline for UE's demand (Method 1: AEMO default, Method 2: UE Proposed)

For mild temperature days (which could dominate the 10 non-event days prior to the event day), UE's weekday daily demand shape resembles that shown at top-left. If an event is called in the middle of a hot day (and assuming UE delivers the required demand response), the daily demand shape resembles that shown top-middle.

The default AEMO baselining shown in Method 1 essentially takes these two curves and pegs them together at the average of a number of periods before the event start time. When this is done, we get the curves shown in top-right where it is clearly ambiguous what level of demand response is actually being provided.

In recognition of this problem, AEMO and UE agreed to pursue the merits of an alternative baselining method.

UE proposed a baseline method shown in Method 2 which only chooses like-temperature non-event weekdays in recent past shown bottom-left, but also pegs the curves at one time interval prior to the event start shown bottom-right. Clearly this provides a much better comparison to estimate the actual demand response delivered and this can be seen by the gap between the curves at any point in time.

AEMO and UE ultimately negotiated a position on the preferred baseline method based on the following principles:-



1. the qualifying baseline days (for the like-temperature days) are to be the most recent 10 non-event, non-holiday, weekdays with maximum temperatures within the band of +4degC to -4degC of the activation day;
2. The period of time to select qualifying days for the 10 day baseline is limited to one year. Given the temperature range, this should allow sufficient time to obtain qualifying days but if it doesn't, the +/-4degC variance will need to be violated to include temperatures lower than the 4degC bottom band;
3. The temperature to be measured at Bureau of Meteorology station Moorabbin Airport station number: 086077; and
4. The event day adjustment will be retained (as per the default baselining method) because the suggested single trading interval before activation is subject to being too heavily influenced by the conditions at activation time and any setup by the service provider. The original trading intervals should still maintain sensitivity for temperature without being unduly influenced by temporal anomalies.

The UE analysis of the 16th January 2018 test day using the three baseline methods (i.e. AEMO default, UE proposed, and AEMO-UE negotiated) are presented below.

AEMO Original Baseline Method

Demand pegged to average of s-3 to s-8. Selected most recent weekdays.

AEMO/AEMO DR Baseline for United Energy (using AEMO default baseline method)		TEST DATE Tue 16/01/2018			
s	Start trading interval (hh:mm AM/PM)	12:00 PM	EDST		
s	Contracted Demand Response MW	12			
s	Simulated Demand Response MW	12			
s	PI tag reference	1	UPPRODUCEMS - SCADA System MW		
s	Number of selected days	10			
s	Trading interval starting time (EDST)	08:00 AM	09:30 AM	10:00 AM	11:30 AM
s	Trading interval	-6	-7	-8	-9
s	MW at time interval (on selected day)				
s	Baseline error %2	352.2	351.8	31.9	50.9
s	Raw	841.5	865.5	892.9	900.8
s	Unadjusted baseline for time interval	36.0	30.7	10.1	8.0
s	Adjustment Factor	17.3			
s	Adjusted Baseline	858.8	882.8	910.2	918.0
s	Delivered Revenue				

UE Suggested Baseline Method

Demand pegged to s-1; Selected most recent weekdays with like temperature conditions.

AEMO/AEMO DR Baseline for United Energy (using UE suggested baseline method)		TEST DATE Tue 16/01/2018			
s	Start trading interval (hh:mm AM/PM)	12:00 PM	EDST		
s	Contracted Demand Response MW	12			
s	Simulated Demand Response MW	12			
s	PI tag reference	1	UPPRODUCEMS - SCADA System MW		
s	Number of selected days	10			
s	Trading interval starting time (EDST)	08:00 AM	09:30 AM	10:00 AM	11:30 AM
s	Trading interval	-6	-7	-8	-9
s	MW at time interval (on selected day)				
s	Baseline error %2	282.3	71.0	8.8	36.6
s	Raw	870.8	890.9	915.9	921.5
s	Unadjusted baseline for time interval	8.8	-4.2	-10.6	-15.9
s	Adjustment Factor	-19.0			
s	Adjusted Baseline	881.8	875.9	896.8	902.5
s	Delivered Revenue				

AEMO Agreed Baseline Method

Demand pegged to average of s-3 to s-8; Selected most recent weekdays with like temperature conditions.

AEMO/AEMO DR Baseline for United Energy (using AEMO agreed baseline method)		TEST DATE Tue 16/01/2018			
s	Start trading interval (hh:mm AM/PM)	12:00 PM	EDST		
s	Contracted Demand Response MW	12			
s	Simulated Demand Response MW	12			
s	PI tag reference	1	UPPRODUCEMS - SCADA System MW		
s	Number of selected days	10			
s	Trading interval starting time (EDST)	08:00 AM	09:30 AM	10:00 AM	11:30 AM
s	Trading interval	-6	-7	-8	-9
s	MW at time interval (on selected day)				
s	Baseline error %2	8.4	30.1	116.1	61.8
s	Raw	870.8	890.9	915.9	921.5
s	Unadjusted baseline for time interval	8.8	-4.2	-10.6	-15.9
s	Adjustment Factor	-19.0			
s	Adjusted Baseline	881.8	875.9	896.8	902.5
s	Delivered Revenue				

Figure 5 Comparison of Baseline assessments for the 16th January 2018 Test event



Company	UNITED									
Contract ID	RB006									
Activation Date	16/01/2018									
Activation start time	1100 (NOTE: time is Eastern Standard Time)									
Activation finish time	1300									
Was this a test	YES									
Contracted MW capacity	12									
Benefiting region	VIC									
Test Results										
	Pre-test interval 2	Pre-test interval 1	Test interval 1	Test interval 2	Test interval 3	Test interval 4	Test interval 5	Test interval 6	Post test interval 1	Post test interval 2
Adjusted baseline MWh	467.953904	472.0851	473.3081822	475.330389	480.6788906	482.3103281	484.6229	483.0969	482.9078	481.2611
Actual demand MWh	463.644675	465.2658	458.731339	459.81689	461.812919	464.779184	473.4895	477.5471	481.0535	485.8969
Delivered reserve MWh			14.57684315	15.51349895	18.86597155	17.53114405				
Calculated MW delivery			29.1536863	31.0269979	37.7319431	35.0622881				
Shortfall (MW)			0	0	0	0				
Average MW delivery during test period	33.2437289									
			BASELINE DATES							
			12-Dec-2017							
			15-Dec-2017							
			20-Dec-2017							
			21-Dec-2017							
			22-Dec-2017							
			29-Dec-2017							
			04-Jan-2018							
			08-Jan-2018							
			10-Jan-2018							
			12-Jan-2018							

Figure 6 AEMO Assessment of the 16th January 2018 Test event using the negotiated baselining method

These results were summarised in Table 1 earlier.



3. Zone Substation Dynamic Voltage Management System (DVMS) Trial

United Energy (UE) is utilising the ARENA project funding to rollout Dynamic Voltage Management System (DVMS) capability to our entire network. This system will allow UE to provide the maximum amount of demand response to AEMO using the voltage reduction technique while keeping customer voltages within safe limits.

Prior to the rollout, DVMS was trialled on UE's Clarinda zone substation in Clayton. The successful completion of this trial in January 2018, now paves the way for this capability to be installed in all of our 47 zone substations.

DVMS works by gathering voltage data provided from customer smart meters on a zone substation and sending it to a Network Analytics Platform (NAP) to make decisions on optimising the voltages according to the dynamic load pattern. The command to select the appropriate customised voltage set-point is then sent to the relevant voltage regulating relay (VRR) at the zone substation. DVMS currently resides within our MOSAIC SCADA system and provides UE with the advanced capability to manage voltage within the network.

DVMS operates by controlling the voltage within the regulatory limits using on-load tap changers at zone substations to manage the customer voltage profiles to $V_{99\%}$ for normal operation and $V_{1\%}$ for demand response operation¹. A range of different voltage set-points are needed to be programmed within the VRRs at each zone substation and as such VRRs need to be replaced with new transformer management relays (either DR-E3 or REG-D). Moreover, protection settings such as over-voltage, under-voltage, etc. of high-voltage (HV) customers supplied by each zone substation need to be taken into consideration when the voltage set-points are determined. Field rectification works (typically distribution transformer tap changes) are also required, following the sequence of the VRR replacement works to maximise the demand response capability.

3.1. DVMS Overview

Figure 7 shows an overview of the end-to-end DVMS.

¹ Refer to AS61000.3.100-2011

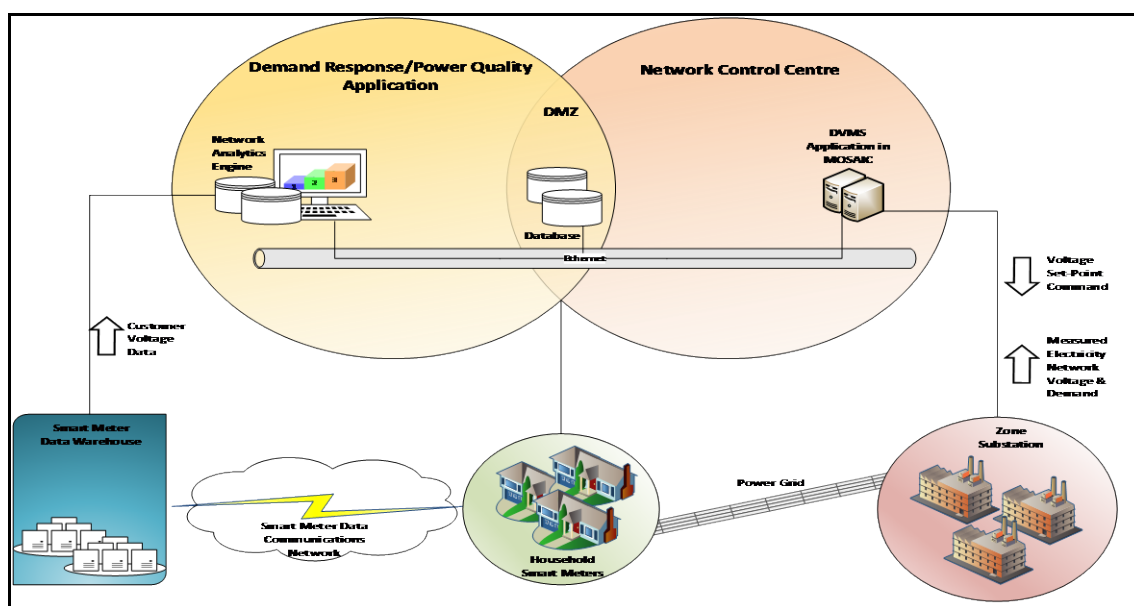
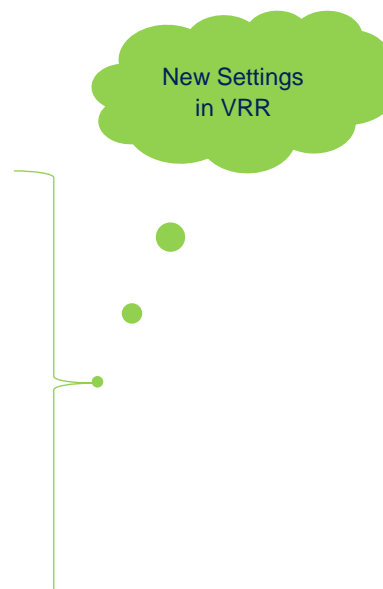


Figure 7 Dynamic Voltage Management System Overview

The existing VRRs in UE's zone substations are not capable of operating with multiple voltage set-points and they need to be upgraded or replaced with new DR-E3 or REG-D transformer management relays to possess the required capabilities. Therefore, the VRRs at CDA zone substation have been programmed with new 7 pre-set bus voltage float set points; namely *DV0* to *DV6*. These settings are programmed with pre-defined setting values in the field VRRs as listed in Table 2.

Table 2: Proposed Voltage Set-Points for Voltage Regulating Relays Deployed in DVMS

No	OLTC Operation Setting
1	Standard
2	Emergency1
3	Emergency2
4	DV0
5	DV1
6	DV2
7	DV3
8	DV4
9	DV5
10	DV6



The setting changes introduce voltage adjustments on the network. Also, the float voltages in both the Master and Follower relays are adjustable.

It should be noted that there is an ability to disable the DVMS at the host.



To achieve the objectives of the DVMS, two main operating modes² are deployed in the NAP: “ $V_{99\%} = 253\text{V}$ (V_{PQ})” and “ $V_{1\%} = 216\text{V}$ (V_{DR})” for power quality improvement and demand response purposes, respectively.

As demonstrated in Figure 8, using $V_{99\%}$ will result in compliance of the 99%³ of the customers with the Victorian Electricity Distribution Code (the Code) limit of 253V. This operating mode can be in use most of the time during the year.

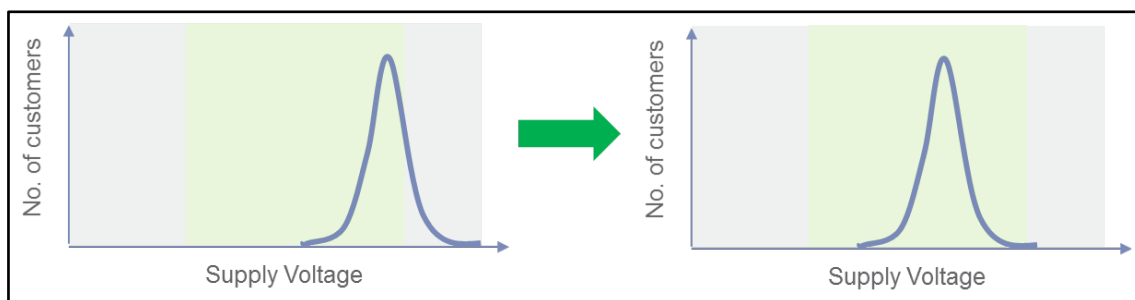


Figure 8 Operating Mode $V_{99\%}$ (V_{PQ}) Deployed by DVMS for Power Quality Improvement

In order to deliver maximum demand reductions when called upon from AEMO without compromising supply quality, the operation will be changed from $V_{99\%}$ to $V_{1\%}$. $V_{1\%}$ can be used to reduce the voltage levels at the selected zone substations by retaining 99%⁴ of the customers in compliance with the Code limit of 216V as demonstrated in Figure 9.

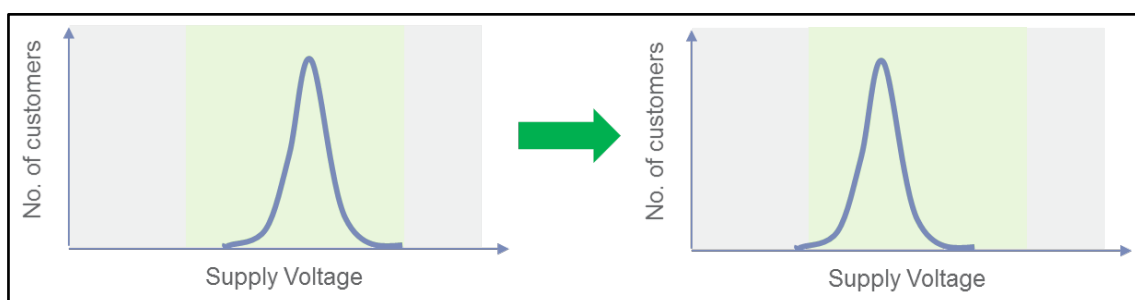


Figure 9 Operating Mode $V_{1\%}$ (V_{DR}) Deployed by DVMS for Demand Response

To increase the level of voltage reduction and consequently demand reduction, UE plans to adjust the tap settings of distribution transformers to narrow the bell curve demonstrated above and also rectify the under-voltages received by the customers at the left side of the histogram.

Since the existing VRRs do not possess the capability of regulating the voltage with multiple set-points, UE has used the existing emergency voltage set-point capability of a subset of zone substations to reduce the demand for the 2017/18 summer to deliver the 12MW of demand response as an interim measure. While the replacement of the VRRs will be undertaken over the next two years to allow progressive operation of the DVMS at each zone substation, it is proposed to retain the Emergency 1 and 2 voltage set point capability to maintain maximum operating flexibility.

² The third mode is also available to minimise the number of non-compliant customers when these two operating modes cannot result in improvement of quality of supply.

³ According to AS 61000.3.100-2011.

⁴ According to AS 61000.3.100-2011.

3.2. DVMS Context

Figure 10 demonstrates different parts of the DVMS.

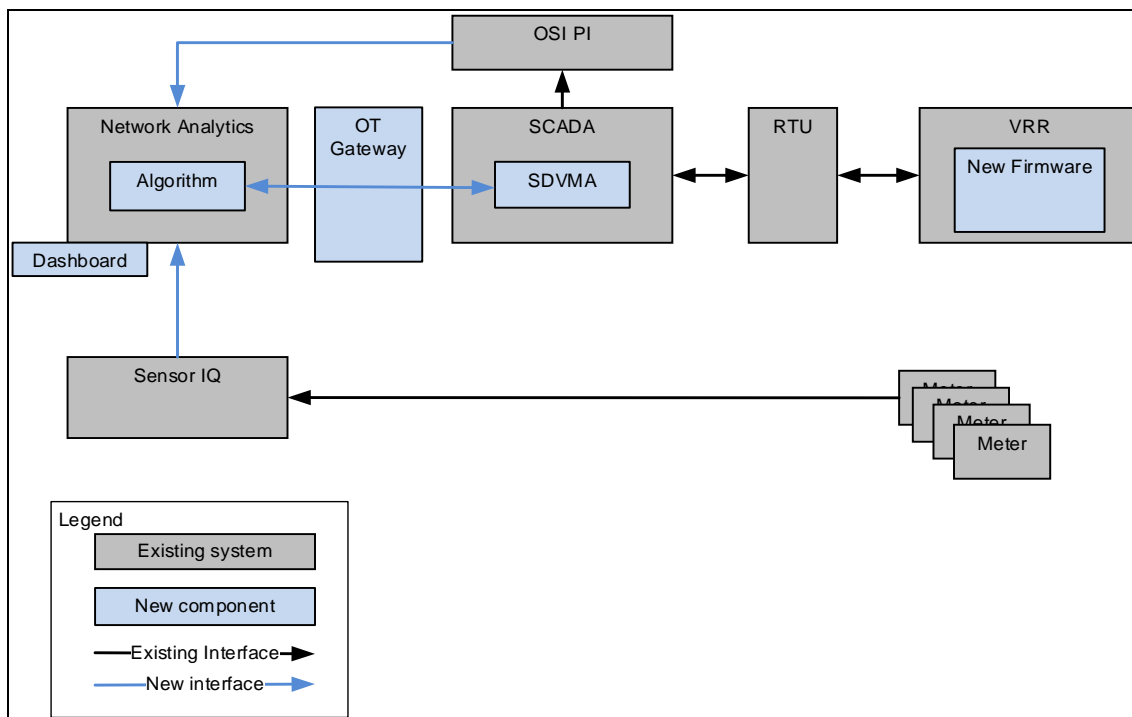


Figure 10 Existing and New Sub-Systems required for Implementing Dynamic Voltage Management System

DVMS consists of below sub-systems:

- **VRRs:** VRRs need to be implemented with new firmware to provide new dynamic voltage set-points to support the DVMS scheme.
- **RTUs:** Remote Terminal Units.
- **SCADA:** MOSAIC SCADA System.
- **SDVMA:** The new SCADA dynamic voltage management application (SDVMA) developed by CGI company that is part of the MOSAIC SCADA system. SDVMA periodically seeks the voltage recommendations from the OT⁵ Gateway and applies the latest recommendation to the field VRRs after validation.
- **OT Gateway:** New infrastructure to enable security compliant integration from Corporate network into the OT network.
- **Network Analytics Algorithm:** New algorithm developed in NAP to generate voltage recommendations for zone substation VRRs based on smart meter data via SensorIQ.
- **Network Analytics Dashboard:** New dashboard developed in NAP to display smart meter voltages for given zone substation.

3.2.1. Network Analytics Platform

Table 3 summarises the DVMS-related business requirements extracted from the Network Analytics Business Requirements Specification upon which the design for the algorithm has been developed. These business requirements have been deployed for the trial with recommendation for improvements given in Section 3.4.8.

⁵ Operational technology.



Table 3: Business Requirements for the Network Analytics Applications for Dynamic Voltage Management System

No	Description
NAP_1	The solution requires the ability to automatically calculate instructions for the dynamic voltage set-point of the zone substation transformer based on smart meter voltage data analytics. The algorithm required is to identify low-voltage (LV) population profiles that can be shifted to minimise putting customers outside of the Code limits. The algorithm is to run at every minute.
NAP_2	<p>The solution requires the ability to automatically monitor the dynamic voltage set-points of the CDA zone substation based on decisions resulting from analytics calculations and should be expandable to other zone substations.</p> <p>The solution requires an interface from NAP to MOSAIC SCADA to support generation of a control message (voltage recommendation) to change the VRR voltage set-point. This interface will exchange messages at a maximum of 1-minute intervals.</p>
NAP_3	The solution will provide recommendations using standard SCADA naming conventions for relevant VRR voltage set-points.
NAP_4	The solution requires NAP to be advised via an acknowledgement (Ack) message that the control message was actioned.

The algorithm design deployed in NAP for DVMS is as follows:

1. The analysis of the smart meter data shall be manually switchable between two modes of control:
 - a. $V_{1\%} = V_{DR}$ – shall control to a level that ensure no more than 1% of the customers on the zone substation are under 216V;
 - b. $V_{99\%} = V_{PQ}$ – shall control to a level that ensure no more than 1% of the customers on the zone substation are over 253V; and
 - c. When there are more than 1% of customers experiencing over-voltages and under-voltages, then the algorithm shall control to ensure that the maximum number of customers stay compliant (between 216V and 253V).
2. The control to change from a $V_{1\%}$ to $V_{99\%}$ control limit or vice versa shall be done from MOSAIC SCADA and interfaced to the NAP algorithm.
3. The readings that are recording abnormally low or abnormally high values (both configurable) such as sites which are experiencing brown-out, voltage sags due to short circuits or outages shall be removed via a filter:
 - a. Smart meter voltage data under 203V shall be ignored from the control algorithm; and
 - b. Smart meter voltages data over 277V shall be ignored from the control algorithm.
4. The number of smart meter reads received, as well as their timeliness, is assessed to decide if the data present is a current statistically-valid sample:
 - a. Data older than 10 minutes shall not be analysed; and
 - b. 100% of zone substation population's data shall be analysed to produce the voltage recommendation.
5. The algorithm shall run based on historical data received.



6. A recommendation shall not cause a recommended step change of more than 2 steps (based on running every 5 minutes).
7. A change recommendation shall not be based on a change that was implemented within 2 minutes either side of the data time stamp being analysed to recommend the new change.
8. The recommendation shall have two time stamps:
 - a. The time the recommendation was produced; and
 - b. The data time stamp the recommendation was based on.
9. A second round of checks shall be performed to limit the changes from pushing customers outside of the Code limits. There are three possible VRR setting change values:
 - a. No voltage change is required;
 - b. Change voltage set-point to x; and
 - c. No confidence/not enough data, no recommendation issued.
10. The algorithm shall filter recommendations such that there is on average only 6 recommendations output to SCADA per day.
11. Once the raw VRR voltage setting change recommendation is calculated, the result shall be written to a database location.
12. NAP shall generate an .xml file from the database record of the recommendation.
13. The algorithm shall not cater for split bus conditions. This shall be performed and disabled on the MOSAIC SCADA side.

Figure 11 demonstrates the algorithm design for NAP which has been deployed by the DVMS.

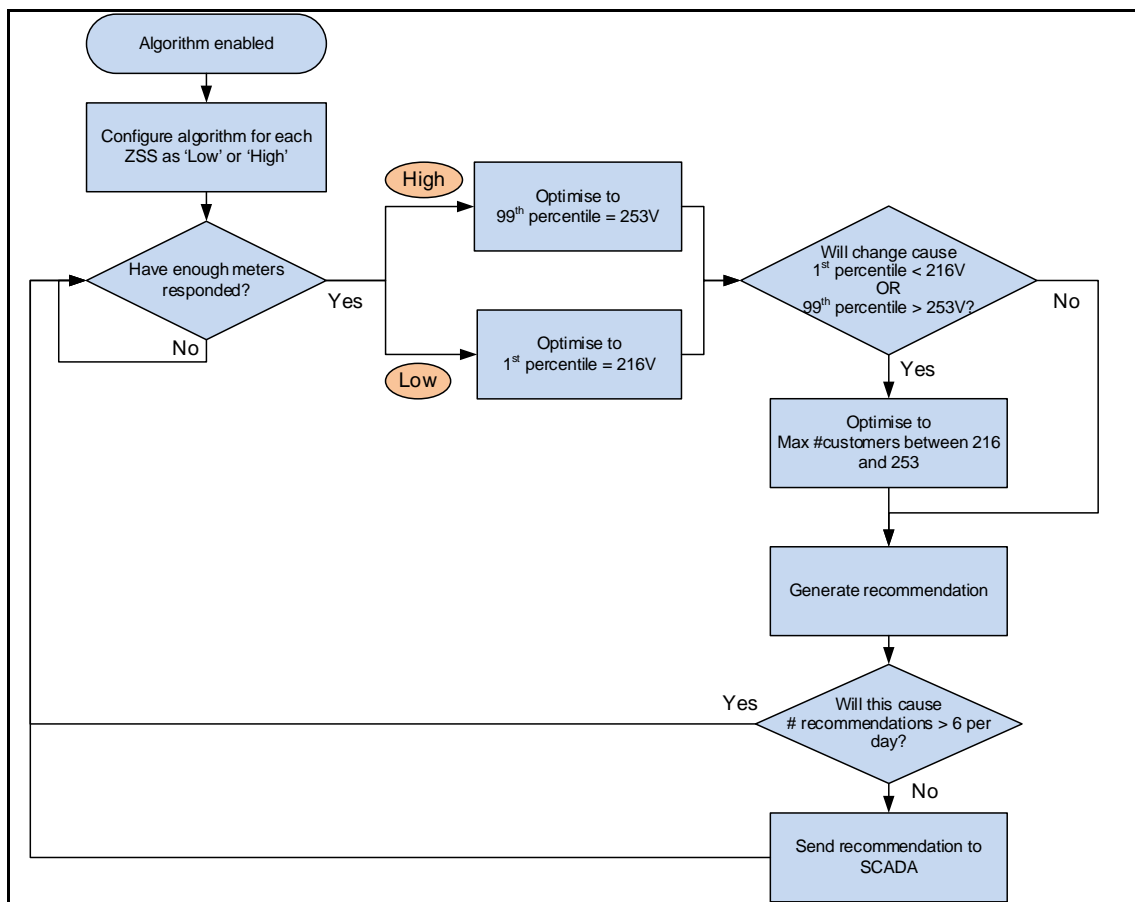


Figure 11 Algorithm Design of the Network Analytics Deployed for Dynamic Voltage Management System

3.2.2. SCADA Dynamic Voltage Management Application

In order to process the voltage set-point changes recommended by NAP, an application (SDVMA) has been implemented in the MOSAIC SCADA system which:

- Receives messages including voltage recommendations and heartbeat from NAP;
- Validates the VRR voltage recommendations and send them to the Master VRR at the nominated ZSS via a standard SCADA control process;
- Manages the control response from the VRR and alarms (if configured to do so) any control failure conditions;
- Maintains and updates local status records for the selected zone substation; and
- Sends updates to NAP.

There are usually multiple transformers (and therefore VRRs) at a zone substation and for SDVMA to operate at a zone substation, the transformers need to be in “Auto” mode with either transformers in “Group” mode and one transformer as “Master” and the others as “Follower” or the transformer is in “Independent” mode. The SDVMA sends a voltage set-point change to only each group in the zone substation. Table 4 explains the various configurations.



Table 4: Business Requirements for the SCADA Dynamic Voltage Management Application

No	Bus-Tie Circuit Breaker	Transformer Control Mode	Transformer Operation Mode	Transformer Operation Status	SDVMA Control Allowed
SDVMA_1	Close	Manual; only the Controller manages the voltage.	N/A	N/A	No
SDVMA_2	Close	Auto, VRR manages the voltage.	Group	Master VRR to monitor its own voltage and control accordingly ⁶ .	Yes; SDVMA can set the voltage set-point on Master VRR.
SDVMA_3	Close	Auto, VRR manages the voltage.	Group	Follower VRR to monitor and follow the Master VRR.	No
SDVMA_4	Open	Manual; Only the Controller manages the voltage.	N/A	N/A	N/A
SDVMA_5	Open	Auto, VRR manages the voltage.	Independent, Each VRR to monitor its own voltage and control accordingly.	N/A	No

To allow a staged implementation of SDVMA, the below requirements need to be met:

1. The SDVMA shall have “Enabled-Manual” and “Enabled-Auto” modes where Enabled-Manual mode shall display the NAP voltage recommendation (via the Operational Display and, if configured, a SCADA alarm) and allow the Controller to set the zone substation VRR request manually, while Enabled-Auto mode shall automatically send the NAP voltage recommendation to the field VRR.
2. Each defined zone substation shall possess Disabled, Manual and Auto modes where:
 - Disabled modes means that no controls are sent to the VRR from SDVMA.
 - Manual means that a Controller can set the NAP voltage recommendation to the VRR and a heartbeat message will be sent too.
 - Auto means that the SDVMA can automatically send the NAP voltage recommendation to the VRR and a heartbeat message will be sent too.

Figure 12 shows the SCADA screen while DVMS is operating in Enabled-Auto mode at CDA zone substation.

⁶ Note this transformer is by convention the lowest numbered transformer e.g. Transformer #1 and if Transformer #1 is out of service, then it will be Transformer #2, etc.

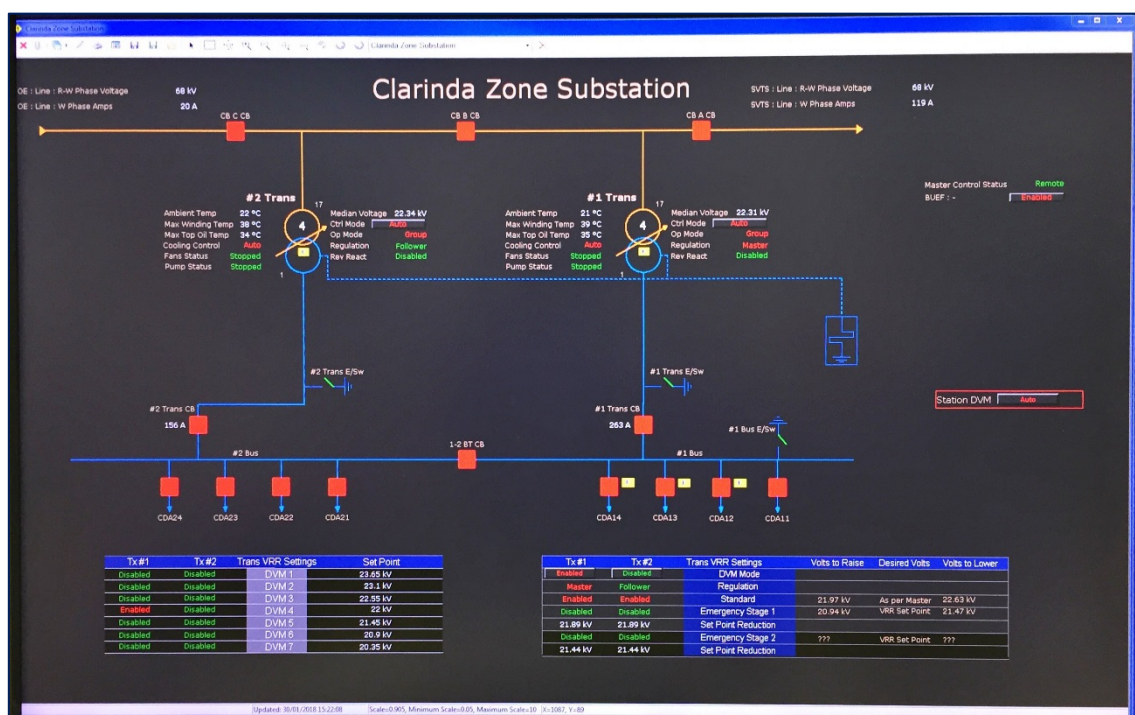


Figure 12 SCADA Screen while Dynamic Voltage Management System is Operating in Enabled-Auto Mode

3.2.3. Zone Substation Voltage Regulating Relays

The previously installed DRMCC-T3 units at CDA zone substation have been replaced with new DR-E3 transformer management relays. The new DR-E3 relays are configured to provide the same functionality provided by the DRMCC-T3 relays. In addition, the new DR-E3 relays are configured with additional pre-set dynamic bus voltage set-points for use by DVMS.

According to Table 2, the new 7 pre-set bus voltage float settings are programmed into both DR-E3 relays (Master and Follower) at the zone substation. Therefore, the new DR-E3 are configured with the same SCADA I/O⁷ as provided by the existing DRMCC-T3 relays with additional remote controls and status points for selection of the new 7 pre-set dynamic bus voltage set points. The new SCADA I/O were approved by UE prior to implementation.

It should be noted that no material changes have been made to the existing transformer cooling control functionality.

Since the DR-E3 had never been used on the UE network therefore to mitigate against the risk of possible SCADA integration issues with the existing station RTUs and the MOSAIC SCADA host, UE requested that the Service Provider investigated and actions where practical bench testing/FAT to validate compatibility.

Section 1 summarises the business requirements for the VRRs (both DR-E3 and REG-D). The business requirements in Section 1 also include the recommendations given in this report.

The following defect points associated with DRMCC-T3 units had been noted when DVMS was planned to implement at CDA zone substation:

- There were inconsistencies on the interface unit (IU) menus and firmware across the DRMCC-T3 population. Also, the Master-Follower naming convention was not easy to understand. This had led to frustrations from the field operators.
- Configuration changes were required for time synchronisation to master RTU.
- Dynamic Master-Follower scheme was not intuitive.

⁷ Input and Output



- More manual testing regarding DVMS was required and the DRMCC-T3 coding platform was less flexible and less modular.
- Implementation DVMS in DRMCC-T3 was a contrived solution that would require more complexity in logic. As a result, there was a greater risk to the project to implement DVMS on DRMCC-T3.
- Only 8 voltage set-points could be implemented.

Therefore, it was decided to replace the existing DRMCC-T3 with DR-E3 to have the above issues solved. DR-E3 units provide:

- Consistent IU menus;
- Firmware version control;
- Allow up to a maximum of 15 voltage set-points;
- Faster and easier to use IU with hotkeys (e.g. easier to view active alarms and common settings); and
- Master-Follower scheme has been refined from the DRMCC-T3 to be more intuitive.

These benefits allow UE to better manage the Dynamic Ratings systems and also give the operators an easier system use. Table 5 compares the features of DR-E3 and DRMCC-T3.

Table 5: Feature Comparison of DRMCC-T3 Vs. DR-E3

Feature	DRMCC-T3	DR-E3
Specifications	Ethernet: 10 Base-T Copper Clock Battery: 2-year life Interface Unit: Text only – 4 lines SCADA: DNP3.0 Communications: FTP, HTTP, Telnet	Ethernet: 10 Base-T Copper100 Base-FX Fibre Optic Clock Battery: 10-year life Interface Unit: Graphical User Interface SCADA: DNP3.0 and IEC61850 Communications: SFTP, FTP, HTTPS, HTTP, SSH, Telnet
Interface Unit	Rubber buttons No numeric keypad No programmable keys Text only display Status LEDs	Capacitive-touch buttons Numeric keypad Programmable functional keys (e.g. easier to view active alarms and common settings) Graphical display with multiple language capability Status LEDs Faster response time Pages created dynamically (no redundant pages) Dynamic functional buttons: (e.g. Home, return) Access levels (limited permissions, user, admin) -20°C to +70°C operating range Standard 19" rack mount or DIN mount options available Can be located locally and/or remotely via



Feature	DRMCC-T3	DR-E3
		fibre optic Menu tree user guide dynamically generated during configuration
Security	None	HTTPS, SFTP, SSH Multiple levels of user access
Thermal model	Based on IEC60354 (1991)	Based on IEC60076 Part 7 (2005)
Parallel Voltage Control	Static Master-Follower	Newly developed Dynamic Master-Follower scheme (Developed in conjunction with Jemena) Simplified user menu Circuit breaker backup signals no longer required Simplifies DR-E3 system I/O and control wiring requirements Future enhancement to allow for capacitor banks without the need for a summation current transformer (CT)
Firmware	No version control	Version control in place
Communications	Modbus, DNP3.0	Modbus, DNP3.0, IEC61850 (Kema certified)
Webpages	DGA value summary only	DGA data is displayed using Duval triangle and pentagon, Roger's ratio and IEEE ratio, etc. Webpages can be configured to show only relevant information
Bushing monitoring	Limited data available	All bushing monitoring data and parameters available
Remote IU	Java required to run virtual IU	Java NOT required at all

3.2.3.1 Failsafe Function

To ensure safe and reliable operation of DVMS, failsafe functionality is required to allow VRRs to safely return to the default voltage set-points in the event of loss of communication to the DR-E3 units.

The used method in DR-E3 is based on a timeout-type feature, where a configurable time delay will return the transformer from a selected voltage set-point back to the default voltage set-point after a time period, unless a NAP voltage recommendation is sent by SDVMA before the timeout occurs. The intended use for this is that SDVMA periodically sends out the NAP voltage set-point to VRRs (even if it is not changing) which will continually reset the timeout timer. If the communication path is lost, the settings will time out and revert to the default voltage set-point and an alarm will be raised "Voltage Group SCADA Timeout". The alarm will not trigger if the transformer is already in the default voltage set-point and will clear if a subsequent SCADA control is successfully received.

The default setting for the timeout is 0 second (timeout function disabled) and will have a maximum setting of 7200 seconds (120 minutes). It has been set at 30 minutes for CDA zone substation.



It should be noted that under no other circumstances will the system automatically revert from a dynamic voltage set-point back to the default voltage set-point.

Also, if the transformer is in Dynamic Master-Follower scheme in a Follower role then, the loss of communications has no effect and no alarm will be raised. Only the Master relay (which performs the main automatic voltage regulation function) responds to the loss of communication.

3.2.3.2 Dynamic Master-Follower Scheme

The principle of Master-Follower control is that all paralleled transformers are kept on the same tapping number and move up or down the taps at the same time. One transformer is designated as a “Master” and has the role of monitoring the bus voltage and controlling the tap changer in order to maintain the required voltage. The remaining transformers are “Followers” and control their tap changers in order to maintain the same tap number as the Master. With all transformers on the same tap number (or “in step”), there is negligible circulating current on the bus.

Master-Follower scheme is a suitable method of parallel control for identical or very similar transformers connected in parallel on both primary and secondary sides. The method is not suitable for transformers whose primaries are connected to different buses or whose ratios are not well matched. These situations may result in excessive circulating currents through the transformers.

In traditional Master-Follower parallel control there is a lot of control wiring between transformers to provide feedback to the controller and to carry the raise/lower commands from the Master to the Followers. Many paralleled contacts and circuit logic is required to provide appropriate out-of-step protection and similar alarms. Under DR-E3 Master-Follower control a communication link is used to exchange information about which DR-E3 is Master and what tap position each transformer is on. It is then possible for the Master to determine which tap all the transformers should be on and each Follower relay can then control its own tap position accordingly. Software logic provides the necessary checks, alarms and inhibits to ensure safe and reliable control of the tap changers in this mode. In DR-E3 Master-Follower control, one DR-E3 in each parallel group is selected to the Master mode and all others are selected to the Follower mode.

The DR-E3 offers two Master-Follower schemes: Static and Dynamic. Static Master Follower mirrors the tradition scheme described above – one transformer is manually selected to be the Master and the other transformers are selected to be Followers: if the Master transformer is taken out of service (or trips) then, another transformer must be assigned the Master role otherwise the Follower units will not be able to tap; or if a bus-tie circuit breaker is opened, the assignment of Master and Follower roles will need to be made in order to ensure that each parallel group has a Master and respective Followers.

The Dynamic Master-Follower scheme monitors the circuit breaker status of the transformer LV breakers and the bus-tie breakers and automatically sets the role of each transformer. This means that if the Master transformer is taken out of service (or trips) the system will automatically assign another transformer to be the Master; or if a bus-tie circuit breaker is opened, the system will automatically reallocate the Master and Follower roles depending on the bus configuration. This removes the chance of any operator errors and is an intuitive and safe way to manage a Master Follower substation.

Figure 13 demonstrates the concept of Dynamic Master Follower deployed by DR-E3 units.

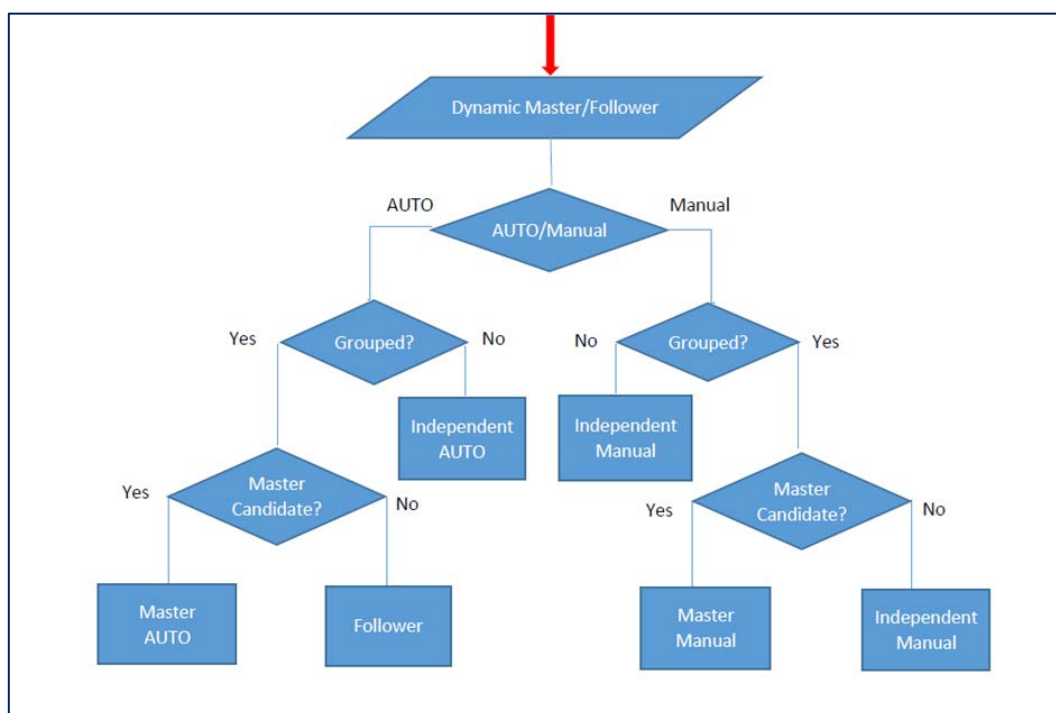


Figure 13 Dynamic Master-Follower Scheme of DR-E3

In Dynamic Master Follower mode, selecting Auto will:

- Select the Master and Followers dynamically and automatically;
- Regulate the voltage automatically;
- Dynamically decide the Group/Independent mode; and
- Dynamically assign Auto/Manual mode to each transformer.

The DR-E3 units at CDA zone substation deploy Dynamic Master-Follower scheme as requested by UE.

3.3. Performance

3.3.1. Pre-Commissioning Process

Prior to commissioning the DVMS trial at CDA zone substation, a test strategy was developed and a comprehensive set of tests was conducted to ensure that DVMS would operate as per UE's expectations.

The test strategy provided criteria for approval of test plans, test phase entry and exit criteria, test execution and test results. It prescribed details of the testing approach for the bench, unit, integration and system acceptance testing phases and the general testing framework to be adhered to across all impacted systems and applications.

Figure 14 shows the overview of testing phases that had been performed on DVMS was commissioned.

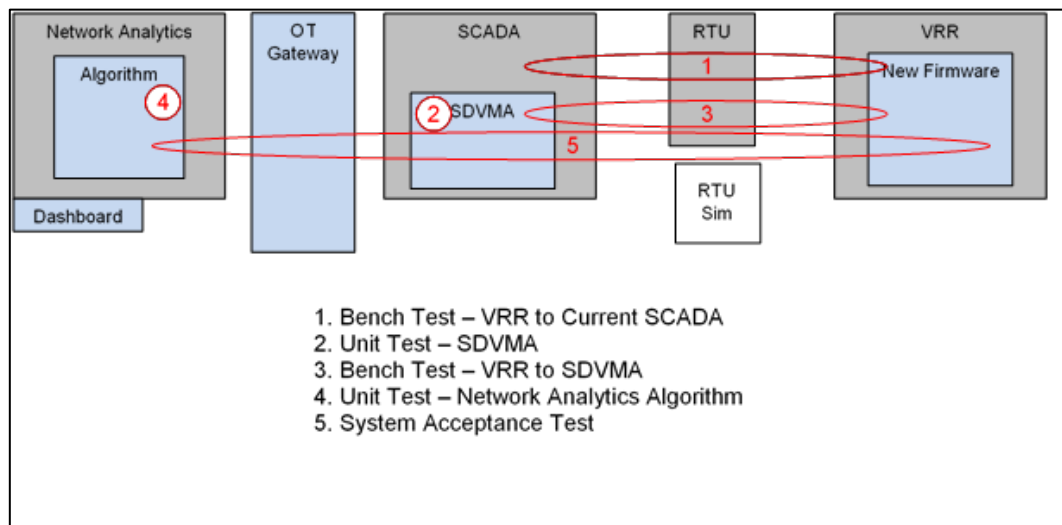


Figure 14 Testing Phases Overview of Dynamic Voltage Management System

During the above tests, details of each test case, results, defects and solutions were documented in Hewlett-Packard Application Lifecycle Management (HP ALM). Figure 15 illustrates the overview of different test cases that were conducted as part of System Acceptance test in HP ALM.

Name	Test Case Name	Type	Status	Iterations	Planned Start...	Responsible...	Pass Date	Time	Planned End
SDVMA UC3 01 Valid NVP hardware and recovery test	SA UC3 01 Valid NVP hardware	MONITOR	Passed	1	16/06/2017	cauliflower	12:52:08 PM		
SDVMA UC3 02 Failure recovery of NVP SDVMA in Ex	SA UC3 02 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	12:58:04 PM		
SDVMA UC3 03 Failure recovery of SDVMA in Ex	SA UC3 03 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	1:13:24 PM		
SDVMA UC3 04 Failure recovery of SDVMA in Ex	SA UC3 04 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	1:14:02 PM		
SDVMA UC3 05 Failure recovery of SDVMA in Ex	SA UC3 05 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	3:10:17 PM		
SDVMA UC3 06 Failure recovery of SDVMA in Ex	SA UC3 06 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	1:21:43 PM		
SDVMA UC3 07 Failure recovery of SDVMA in Ex	SA UC3 07 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	1:22:27 PM		
SDVMA UC3 08 Failure recovery of SDVMA in Ex	SA UC3 08 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	1:28:12 PM		
SDVMA UC3 09 Failure recovery of SDVMA in Ex	SA UC3 09 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	1:28:17 PM		
SDVMA UC3 10 Failure recovery of SDVMA in Ex	SA UC3 10 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	1:32:09 PM		
SDVMA UC3 11 Failure recovery of SDVMA in Ex	SA UC3 11 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	1:48:17 PM		
SDVMA UC3 12 Failure recovery of SDVMA in Ex	SA UC3 12 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	12:07:51 PM		
SDVMA UC3 13 Failure recovery of SDVMA in Ex	SA UC3 13 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	3:25:25 PM		
SDVMA UC3 14 Failure recovery of SDVMA in Ex	SA UC3 14 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	2:37:51 PM		
SDVMA UC3 15 Failure recovery of SDVMA in Ex	SA UC3 15 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	2:40:13 PM		
SDVMA UC3 16 Failure recovery of SDVMA in Ex	SA UC3 16 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	2:41:17 PM		
SDVMA UC3 17 Failure recovery of SDVMA in Ex	SA UC3 17 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	2:52:40 PM		
SDVMA UC3 18 Failure recovery of SDVMA in Ex	SA UC3 18 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	2:53:19 PM		
SDVMA UC3 19 Failure recovery of SDVMA in Ex	SA UC3 19 Failure recovery	MONITOR	Passed	1	16/06/2017	cauliflower	2:52:15 PM		

Figure 15 Overview of DVMS System Acceptance Test Documented in Hewlett-Packard Application Lifecycle Management

3.3.2. Modelling

In order to study the impact of dynamically regulating the voltage, in particular under-voltages, on high-voltage (HV) customers, all of the HV feeders supplied by CDA zone substation were modelled in PSS/SINCAL. Figure 16 illustrates the single-line diagram of CDA zone substation. This arrangement was deployed to model this zone substation in PSS/SINCAL.



Figure 16 Single-Line Diagram of Clarinda Zone Substation

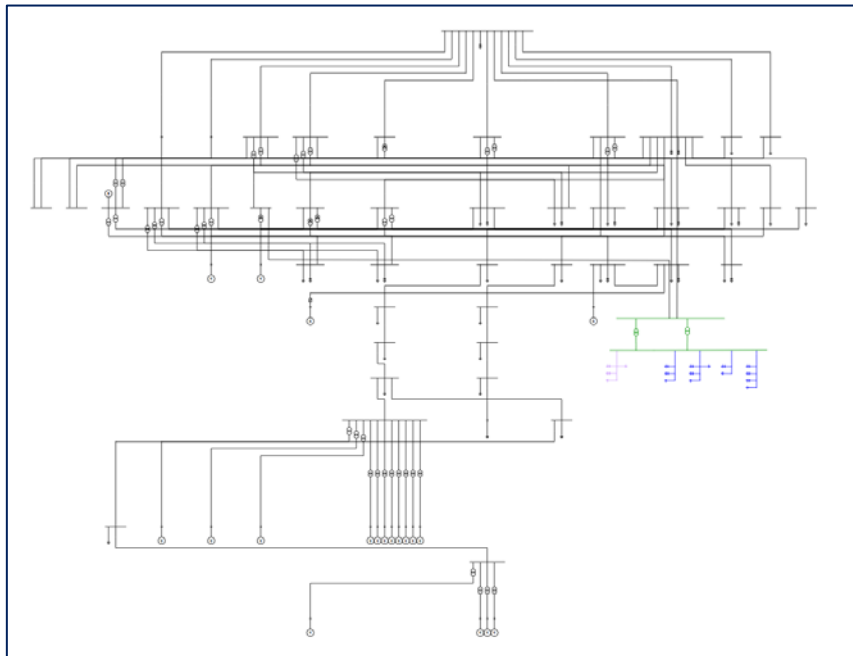


Figure 17 Zone Substations including CDA Supplied by Springvale Terminal Station Modelled in PSS/SINCAL

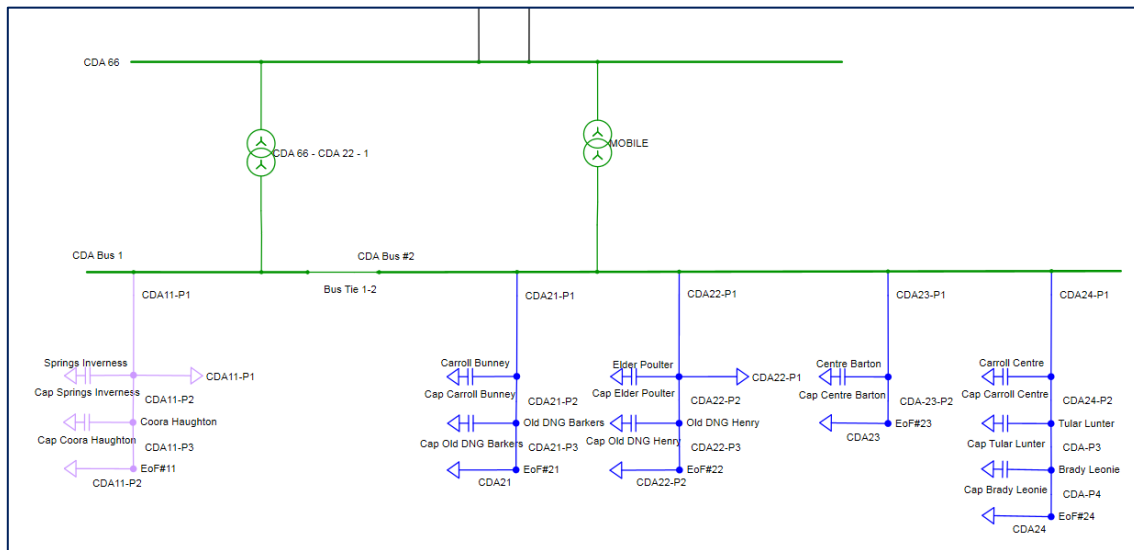


Figure 18 Modelling of HV Feeders Supplied by Clarinda Zone Substation in PSS/SINCAL

Table 6 lists all of the HV feeders supplied by CDA zone substation. According to this table, CDA22 is the longest feeder and should be taken into account when under-voltages are studied.

Table 6: List of High-Voltage Feeders Supplied by Clarinda Zone Substation

HV Feeder	No of Distribution Substations	LV lines (km)	LV Cables (km)	HV Lines (km)	HV Cables (km)
CDA11	24	16.8	1.0	7.3	1.9
CDA12	0	0.0	0.0	0.0	0.0
CDA13	0	0.0	0.0	0.0	0.0
CDA14	0	0.0	0.0	0.0	0.0
CDA21	23	7.5	1.2	4.4	0.6
CDA22	44	25.9	3.5	13.6	4.4
CDA23	61	42.5	3.0	17.3	2.1
CDA24	46	38.5	0.9	13.0	1.8

By running load flow analysis in PSS/SINCAL, the voltage delivered to the HV customer can be estimated. Figure 19 shows the result for a peak demand of 29.14MW supplied by CDA zone substation without DVMS scheme in service.

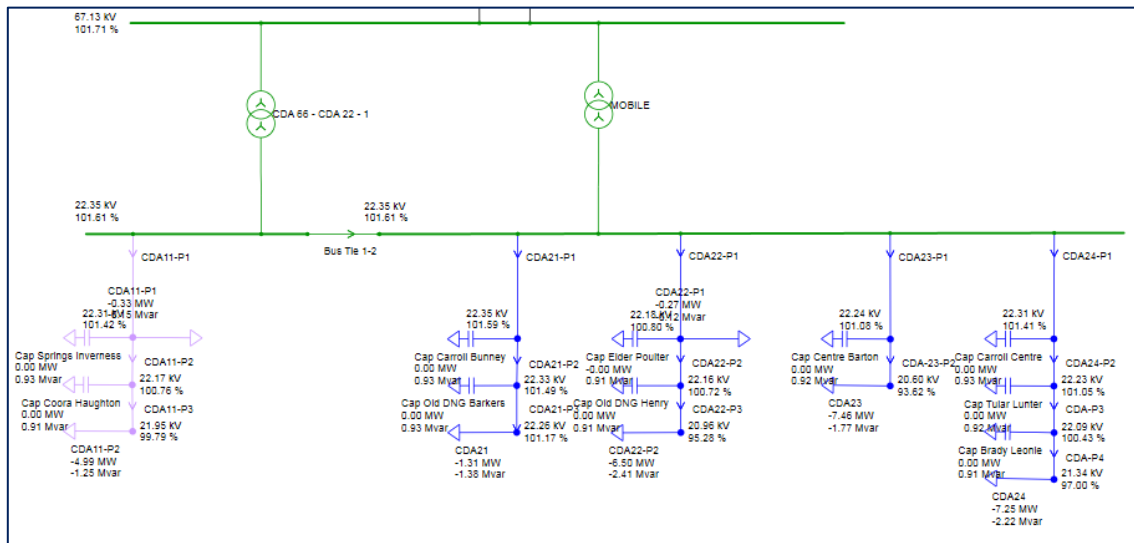


Figure 19 Results of PSS/SINCAL Load Flow Analysis for a Peak Demand Day for Clarinda Zone Substation without DVMS in Service

According to this figure, the voltage delivered to the HV customer is within the Code limits of 22kV \pm 6% and no under-voltages are received by the HV customer.

To investigate the impact of DVMS on voltage levels delivered to the HV customer, the proposed voltage set-points for CDA zone substation have been deployed. Figure 10 summarises the voltage set-points for CDA zone substations. The set-points highlighted in **green** had been already available with the previous firmware of DRMCC-T3 while the highlighted ones in **orange** are the dynamic voltage set-points that are deployed for DVMS scheme.

Table 7: Proposed Voltage Set-Points for Clarinda Zone Substation Post Implementing Dynamic Voltage Management System

Voltage Set-Point	Voltage (kV)	Voltage (pu)	Voltage (secondary)
V_{std}	22.59	1.027	113.0
$V_{emergency1}$	21.92	0.996	109.6
$V_{emergency2}$	21.46	0.976	107.3
$V_{overvoltage}$	24.20	1.100	121.0
$V_{undervoltage}$	19.80	0.900	99.0
V_{sp1}	23.65	1.075	118.3
V_{sp2}	23.10	1.050	115.5
V_{sp3}	22.55	1.025	112.8
V_{sp4}	22.00	1.000	110.0



Voltage Set-Point	Voltage (kV)	Voltage (pu)	Voltage (secondary)
V_{sp5}	21.45	0.975	107.3
V_{sp6}	20.90	0.950	104.5
V_{sp7}	20.35	0.925	101.8

Therefore, V_{sp3} , V_{sp5} , V_{sp6} and V_{sp7} have been applied to the PSS/SINCAL model to investigate the DVMS impact on the HV customer. To consider the worst-case scenario, the load of 29.14MW supplied by CDA zone substation has been applied to the model.

Figure 20 and Figure 21 show the results of load flow study in PSS/SINCAL with the above voltage set-points applied to the CDA zone substation transformers. According to these figures, in a peak demand day V_{sp7} is the only voltage-set-point that would cause under-voltages received by the HV customer. However, this voltage set-point is not defined for peak demand days. Also, it can be included that DVMS applying V_{sp6} would result in a higher level of demand response compared to the traditional technique using emergency voltage set-points(in this case $V_{emergency2}$) when called upon from AEMO.

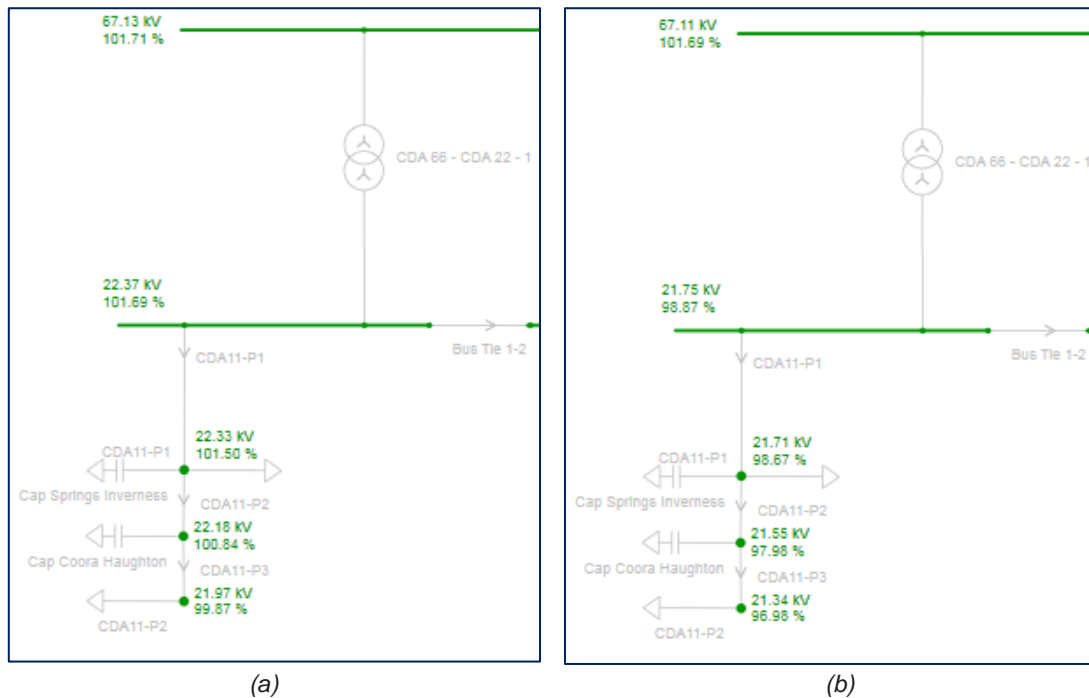


Figure 20 Voltage Delivered to HV customer with Voltage Set-Points of V_{sp3} , (a), and V_{sp5} , (b), Applied to CDA Zone Substation Transformers

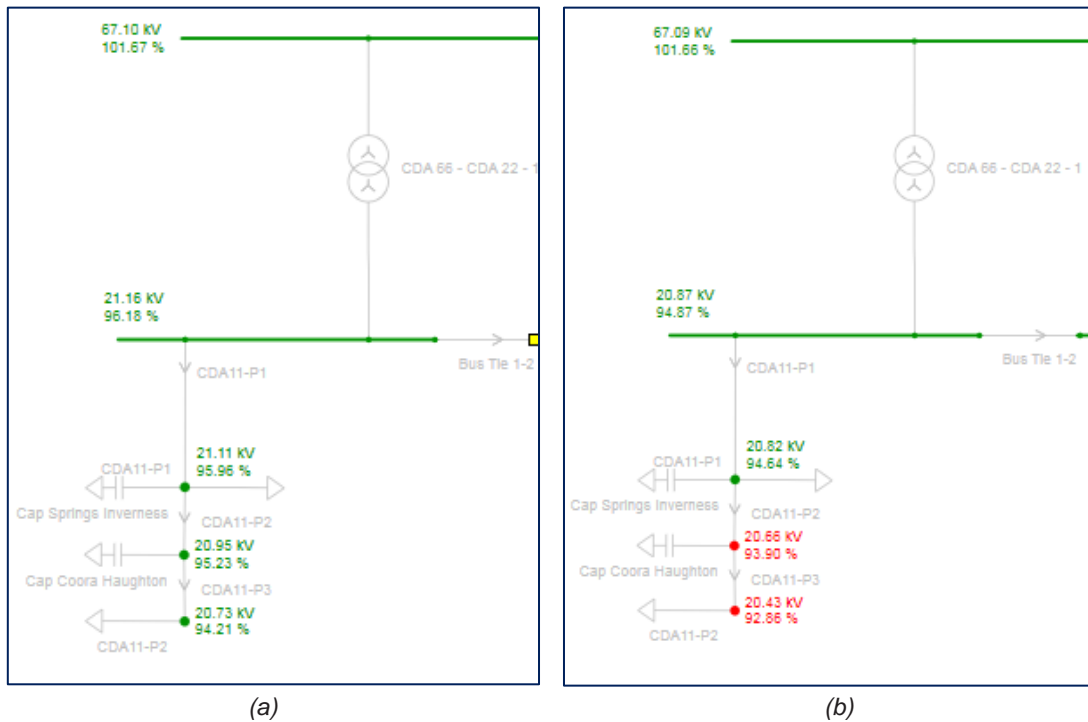


Figure 21 Voltage Delivered to HV customer with Voltage Set-Points of V_{sp6} , (a), and V_{sp7} , (b), Applied to CDA Zone Substation Transformers

3.3.3. Commissioning

After completing all of the tests defined in Test Strategy, a commissioning plan was developed to detail the process of implementing the DVMS in Production environment in a step-step manner. As a result, DVMS was switched into Enabled-Manual and then Enable-Auto on Thursday, 14th December 2017. Figure 22 and Figure 23 show the impact of DVMS on the bus voltages and also the tap positions of the CDA zone substation transformers. It should be noted that as per the commissioning plan, DVMS was retained in Enabled-Auto mode only during the working hours on Thursday, 14/12/2017.

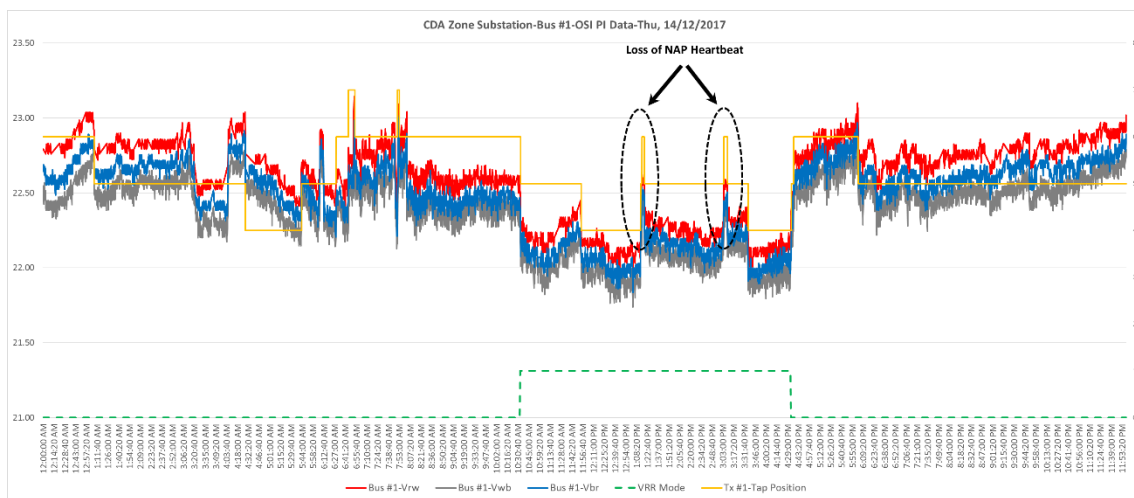


Figure 22 Impact of DVMS on Voltage Bus #1 and Tap Position of Transformer #1 at CDA Zone Substation on Thursday, 14/12/2017

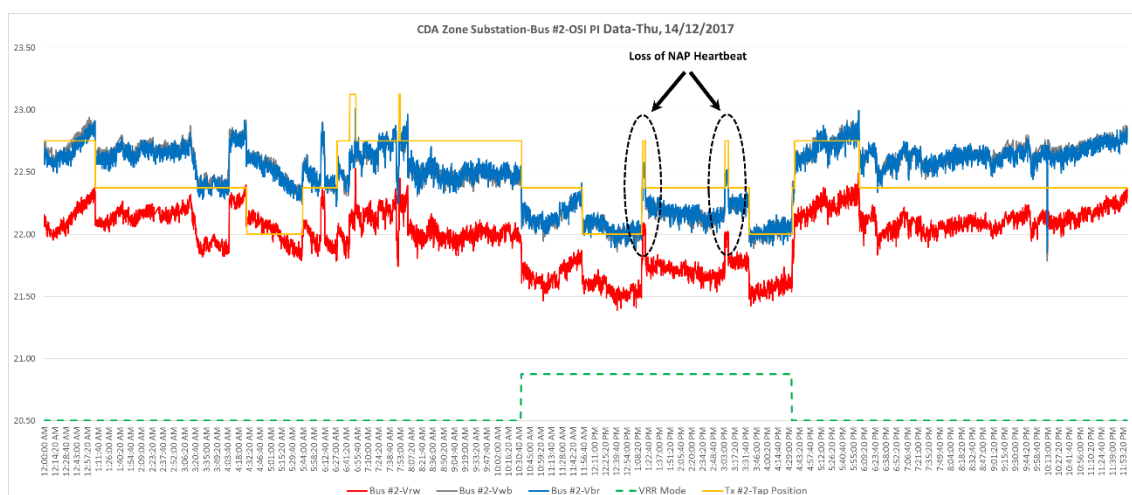


Figure 23 Impact of DVMS on Voltage Bus #2 and Tap Position of Transformer #2 at CDA Zone Substation on Thursday, 14/12/2017

According to the above figures, it can be observed that by enabling the DVMS at 10:35 am, the bus voltages at CDA zone substation immediately reduced to a lower level and the on-load tap changers (OLTCs) changed the transformer taps from level 6 to 5. Both transformers also followed a similar pattern as they were under Dynamic Master-Follower scheme. Based on the voltage data from smart meters, the transformer taps were switched between level 5 and 4.

DVMS was disabled at 04:35 pm and it can be seen the transformer taps were returned to a higher level (from 4 to 6) and then changed according to the load profile.

The voltage profiles for customers supplied by CDA zone substation prior to and after commissioning the DVMS are given in Figure 24 and Figure 25, respectively.

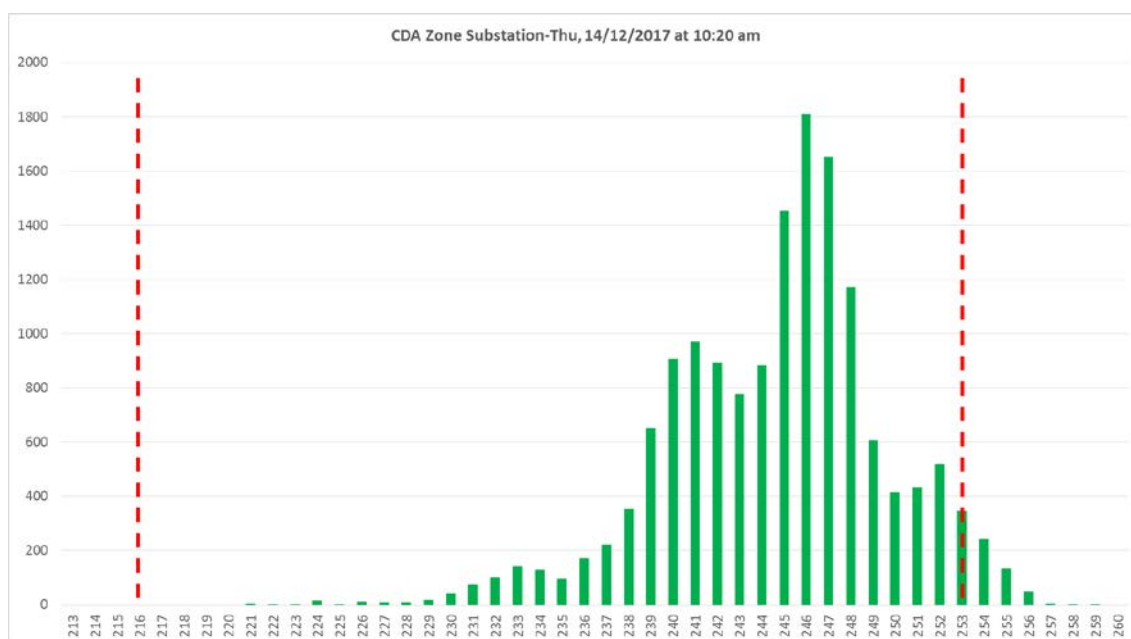


Figure 24 Customers' Voltage Profiles for CDA Zone Substation at 10:20 am on Thursday, 14/12/2017 (Prior to Commissioning DVMS)

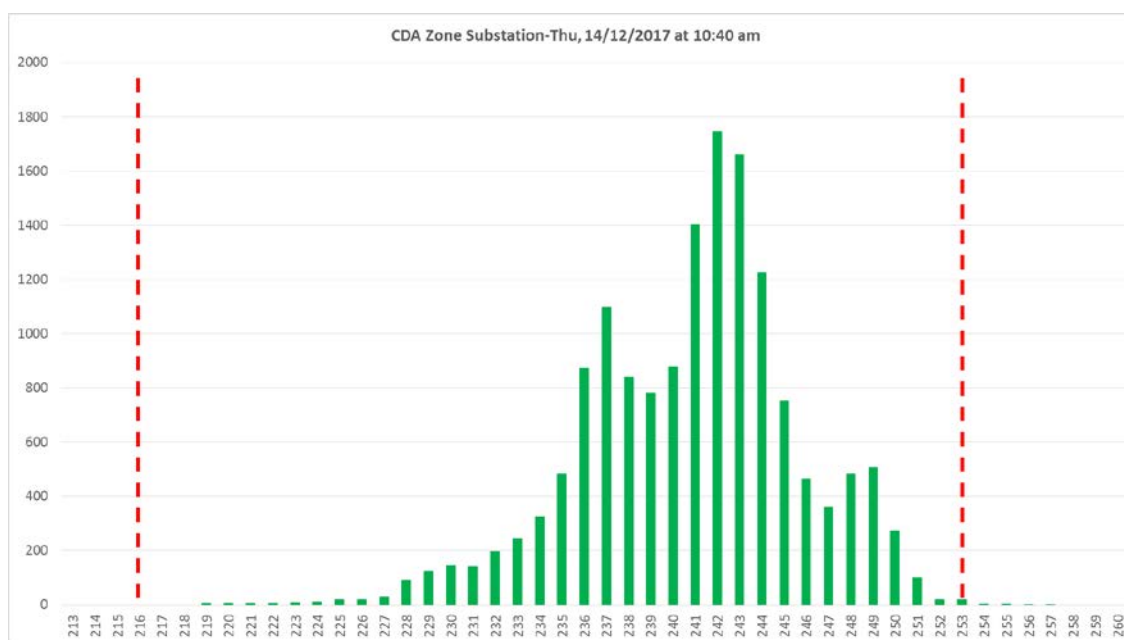


Figure 25 Customers' Voltage Profiles for CDA Zone Substation at 10:40 am on Thursday, 14/12/2017 (Post Commissioning DVMS)

According to the above figures, a significant reduction in voltage levels can be observed that resulted in more compliant customers supplied by this zone substation.

$V_{1\%}$, $V_{50\%}$ and $V_{99\%}$ are calculated for the CDA zone substation's customers prior to and post commissioning the DVMS. These values are summarised in Table 8. According to this table, DVMS resulted in reducing the voltage levels and consequently, a compliant value for $V_{99\%}$.

Table 8: Impact of Commissioning Dynamic Voltage Management System on Customers' Voltage Profiles

Parameter	Prior to Commissioning DVMS 10:20 am	Post Commissioning DVMS 10:40 am
$V_{1\%}$	231V	228V
$V_{50\%}$	245V	241V
$V_{99\%}$	255V	250V

3.3.4. Network Normal Operating Conditions

DVMS was disabled during the 2017 Christmas holiday and then switched back to Enabled-Auto at 09:40 am on Tuesday, 2nd January 2018. After a few days of operating during working hours only, DVMS was retained in service after hours on Thursday, 4th January 2018. Figure 26 and Figure 27 demonstrate the impact of DVMS on bus voltages and also tap positions of the zone substation transformers for two consecutive days.

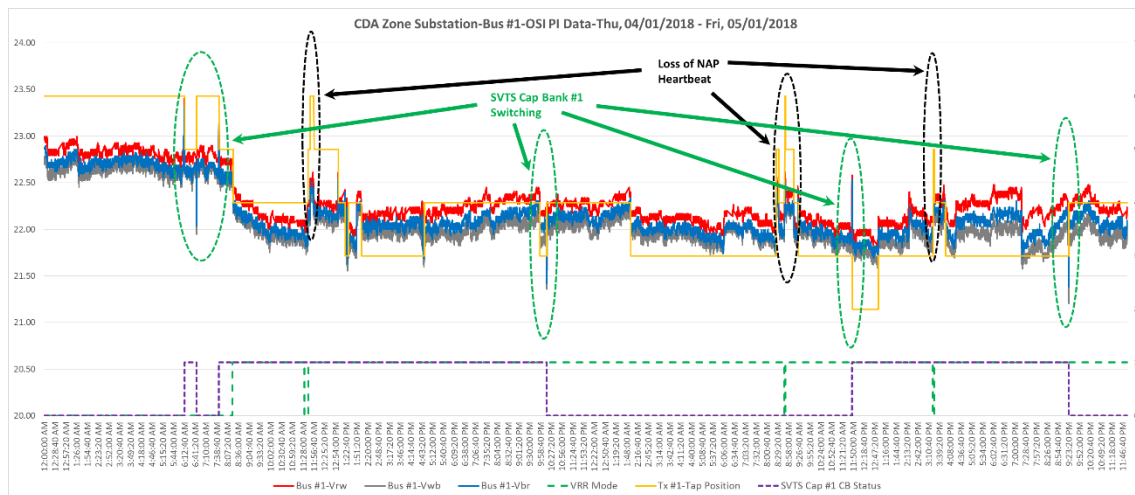


Figure 26 Impact of DVMS on Voltage Bus #1 and Tap Position of Transformer #1 at CDA Zone Substation from Thursday, 04/01/2018 to Friday, 05/01/2018

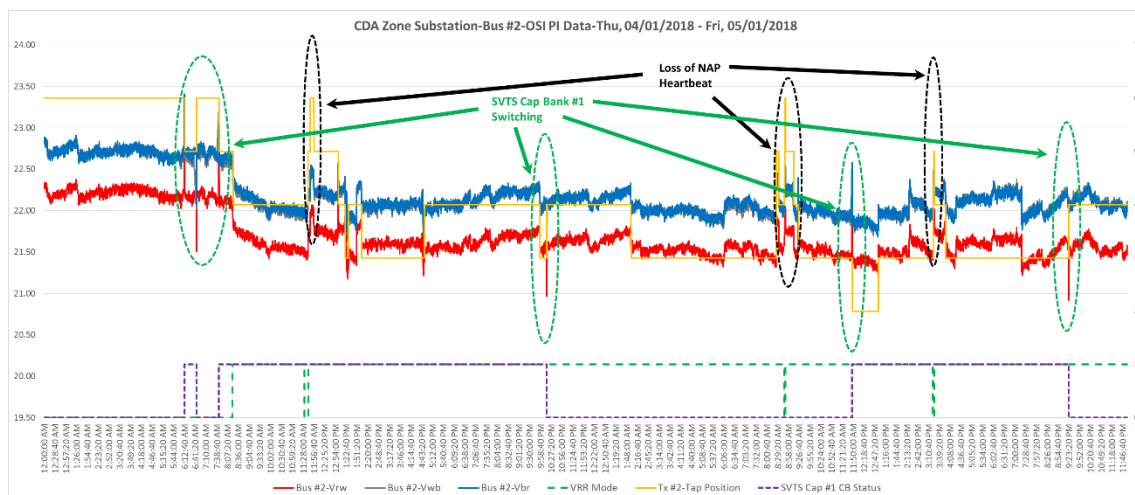


Figure 27 Impact of DVMS on Voltage Bus #2 and Tap Position of Transformer #2 at CDA Zone Substation from Thursday, 04/01/2018 to Friday, 05/01/2018

According to the above figures, there were two interruptions on VRR Mode (the SCADA point showing enable/disable mode of DVMS) that resulted in reverting the transformers back to the default voltage set-points. These momentary interruptions were intentionally applied to confirm that the loss of the NAP heartbeat for SDVMA would cause the transformers to revert back to the default voltage set-points immediately and also, SDVMA would automatically resume again once the new NAP heartbeat is received by SDVMA. Based on the result, this test was successfully passed and confirmed this functionality of the system.

Figure 26 and Figure 27 also confirm that switching in and out the SVTS capacitor bank #1 would result in voltage swells and dips, respectively. The momentary impact of capacitor banks at supplying terminal stations on DVMS need to be taken into account for rolling out the DVMS across the distribution network.

To validate the performance of DVMS on a hot day, it was monitored on Saturday, 6th January 2018 when the temperature reached the maximum of 40.9°C. During test, DVMS was disabled from 2:00 pm to 2:30 pm to confirm the voltage trend at CDA zone substation on a peak demand day when DVMS is not in service. Figure 28 and Figure 29 demonstrate the impact of DVMS on bus voltages and tap position of CDA zone substation transformers #1 and #2, respectively.

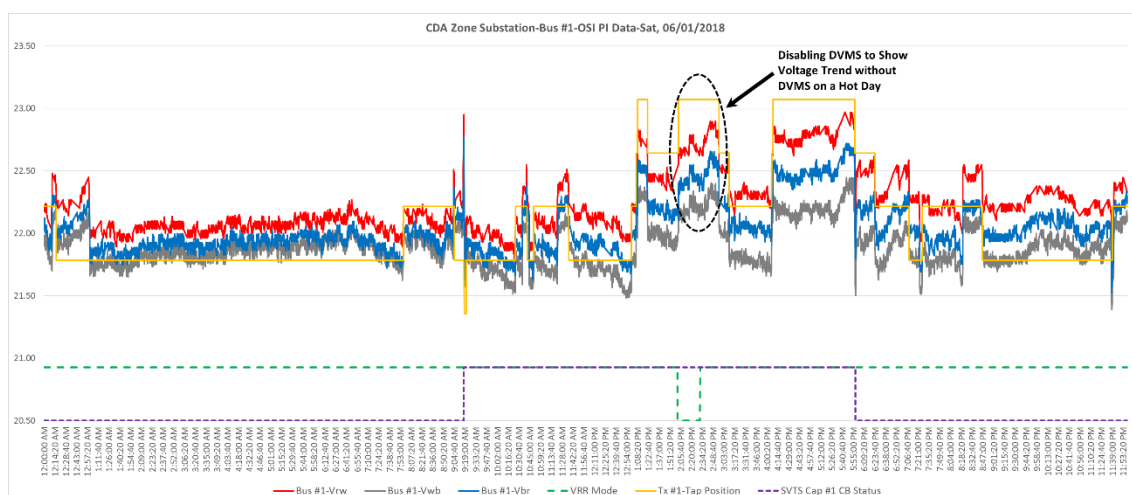


Figure 28 Impact of DVMS on Voltage Bus #1 and Tap Position of Transformer #1 at CDA Zone Substation on Saturday, 06/01/2018

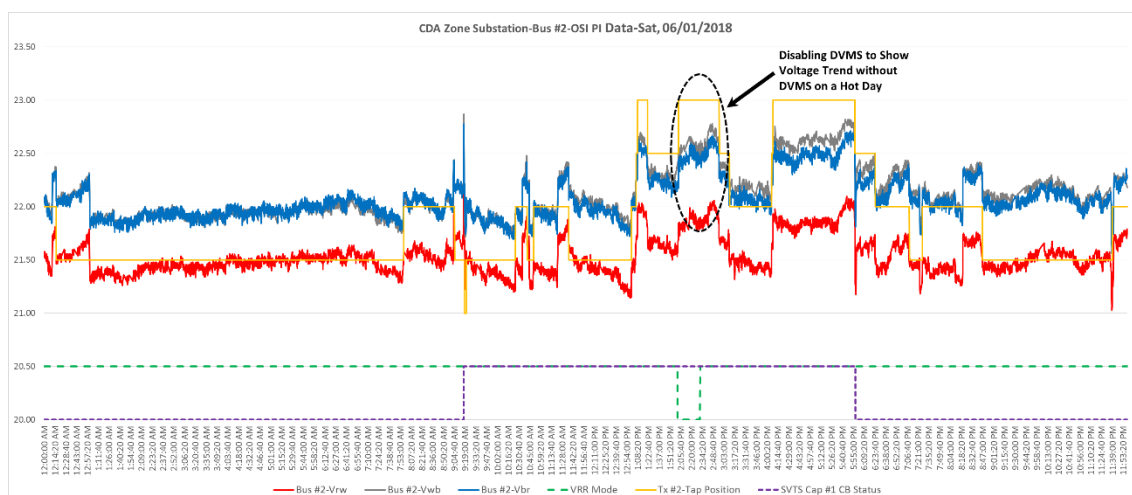


Figure 29 Impact of DVMS on Voltage Bus #2 and Tap Position of Transformer #2 at CDA Zone Substation on Saturday, 06/01/2018

During the peak demand, NAP was operating in the optimisation mode to minimise the number of non-compliant customers (both under-voltages and over-voltages). According to the above figures, it can be seen that by disabling the DVMS, both transformers started tapping up which resulted in more over-voltages.

Figure 30 shows the percentage of under-voltages and over-voltages from Monday, 1st to Wednesday, 10th January 2018. As this figure demonstrates, DVMS can eliminate majority of the voltage excursions however, there are a number of voltage events that need to be addressed by adjusting the tap settings of distribution transformers. This programme is being executed to ensure the business requirements to manage demand and quality of supply are thoroughly met and satisfied.

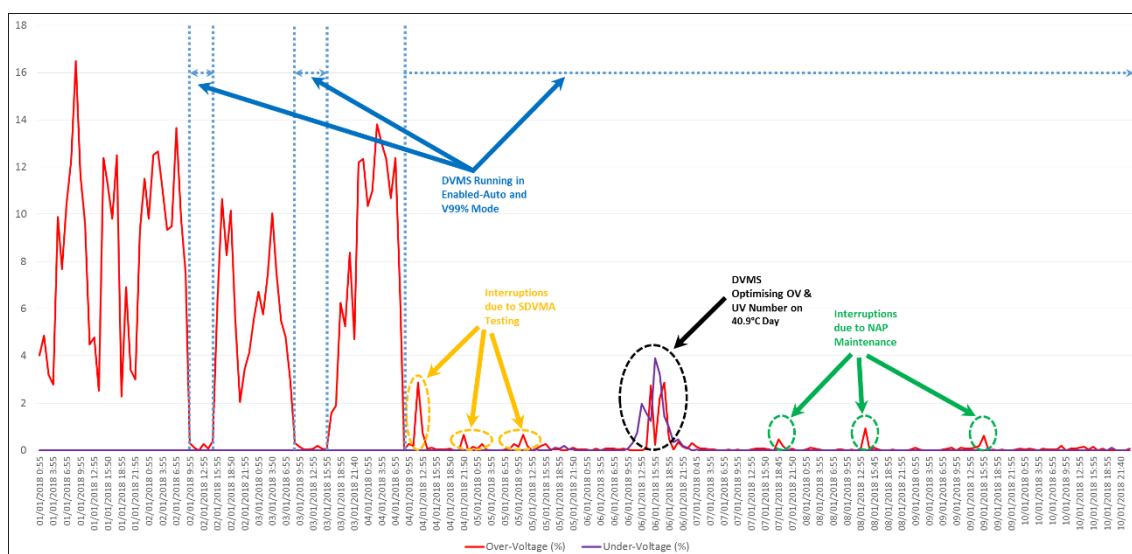


Figure 30 Impact of DVMS on Over-Voltages and Under-Voltages Received by CDA Zone Substation's Customers from Monday, 01/01/2018 to Wednesday, 10/01/2018

As this figure shows, DVMS was intermittently switched off during this period for the below reasons:

- Training of Controllers on how to use the system (potentially a switch off and back on a few minutes later per Controller shift);
- During Saturday's heat to observe what impact automated control imposed by DVMS had on customers' voltages;
- Evaluate the DVMS response with Monday's outage of NAP Production systems and correct cutover from/to disaster recovery (DR) and then handling of potentially lost communication/heartbeats;
- Confirm managing of the impact of SVTS cap bank switching on voltage profiles and also to what extend NAP's "control smoothing" can handle the consequent voltage swells and dips.

As a result of the above activities:

- Cutover occurred from NAP DR to NAP Production and everything worked as expected on the new system.
- It was confirmed that the loss of the 2-minute heartbeat caused SDVMA to revert back the transformers to the default voltage set-point. Also, SDVMA automatically resumed the normal operation and sent the NAP recommendations to the Master VRR once the new heartbeat was sent from NAP.
- The heartbeat timeout from 4 to 7 minutes as a result of the cutover to prevent this setting toggle from occurring too frequently (cutover between Production and DR should in most cases take less than 7 minutes). Timeout could be as small as 5 minutes, depending on the timing of the 1st failure.
- NCC disabled DVMS on Saturday mid-afternoon and there were no major change easily visible on what this impact was as NAP and the default voltage set-point at CDA zone substation were at the same level at the time.
- The hot day also highlighted that the 2.5% difference between 2 dynamic voltage set points could potentially be reduced to allow for more granular control of the number of customers over and under the Code limits.

3.3.5. Network Abnormal Operating Conditions

As mentioned earlier in this report, there are two transformers (and therefore, two VRRs) at CDA zone substation and for DVMS to operate, the transformers need to be in Auto and Group mode and one transformer as Master and the other as Follower. DVMS will then send a voltage set-point change to the Master only. Table 4 explains the various configurations:



It should be noted that DVMS can be in either Enabled-Auto or Enabled-Manual mode in normal operating conditions and when the bus-tie circuit breaker at CDA zone substation is closed only.

No automatic action is taken by DVMS in network abnormalities and DVMS shall be switched to Disabled mode by the Controller.

It should also be noted where the bus-tie circuit breaker is opened manually or automatically, the Dynamic Master-Follower scheme is not valid anymore and each VRR will be treated as an independent device. Therefore, the Controller needs to manually disable DVMS and consequently, the VRRs will revert back to the default voltage set-point.

A configurable watchdog timer is available in the VRR to reset the voltage set-point to the default voltage set-point if a NAP voltage recommendation is not received in the configurable period. This is defined as the failsafe scenario during the trial as described in Section 3.2.3.2.

The watchdog timer will be reset when a NAP voltage recommendation to enable a DVMS set-point is received. This includes a control for the voltage set-point which the VRR is already regulating to.

Upon expiry of the watchdog timer, the relay will enact the failsafe action.

In the default normal or emergency voltage set-point including situations in which a request to reduce the demand is received from AEMO, the watchdog timer does not take any action and the Controller needs to manually disable the DVMS and consequently, the VRRs will revert back to the default voltage set-points.

The below scenarios are considered as network abnormal operating conditions and some tests were conducted to evaluate the performance of DVMS in these conditions:

- Bus-tie circuit breaker at CDA zone substation is opened.
- A HV feeder is transferred from/to CDA zone substation.
- LV circuit breaker (22kV) of the Master transformer at CDA zone substation is opened.
- LV circuit breaker (22kV) of the Follower transformer at CDA zone substation is opened.
- Transformers at CDA zone substation are switched to Manual mode.
- Transformers at CDA zone substation are switched to Local mode.
- Emergency voltage set-points of VRRs at CDA zone substation are selected.
- DVMS is running in Enabled-Auto mode and transformers are switched to Manual mode.

1.1.1.1 Performance of DVMS when Bus-Tie Circuit Breaker is opened

To validate the performance of DVMS when the bus-tie circuit breaker is opened, a test was conducted on Wednesday, 20th December 2017. Figure 31 shows the status of CDA zone substation with closed bus-tie circuit breaker and prior to enabling DVMS. As this figure demonstrates, 1,713 customers received over-voltages at 10:00 am.

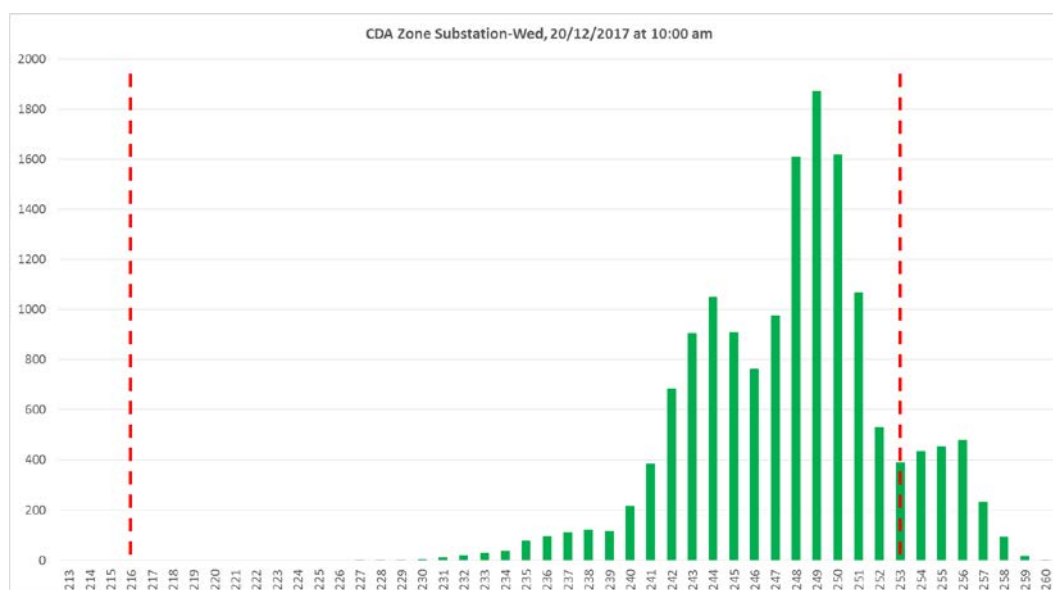


Figure 31 Customers' Voltage Profiles for CDA Zone Substation at 10:00 am on Wednesday, 20/12/2017 (DVMS Disabled & Bus-Tie Circuit Breaker Closed)

By enabling DVMS at around 10:10 am (running in Enabled-Auto and in $V_{99\%}$ mode), the Master transformer (Tx #1) received the NAP voltage recommendation and started tapping down to level 4 (from level 6). Since both transformers at CDA zone substation were operating under Dynamic Master-Follower scheme, the Follower transformer (Tx #2) followed the Master transformer and changed the tap setting from level 6 to level 4. As a result of this tap change, more customers received a voltage supply which was compliant with the Code limit of 253V. Figure 32 shows the customers' voltage profiles for that point of time. It should be noted that the bus-tie circuit breaker was still closed at this stage.

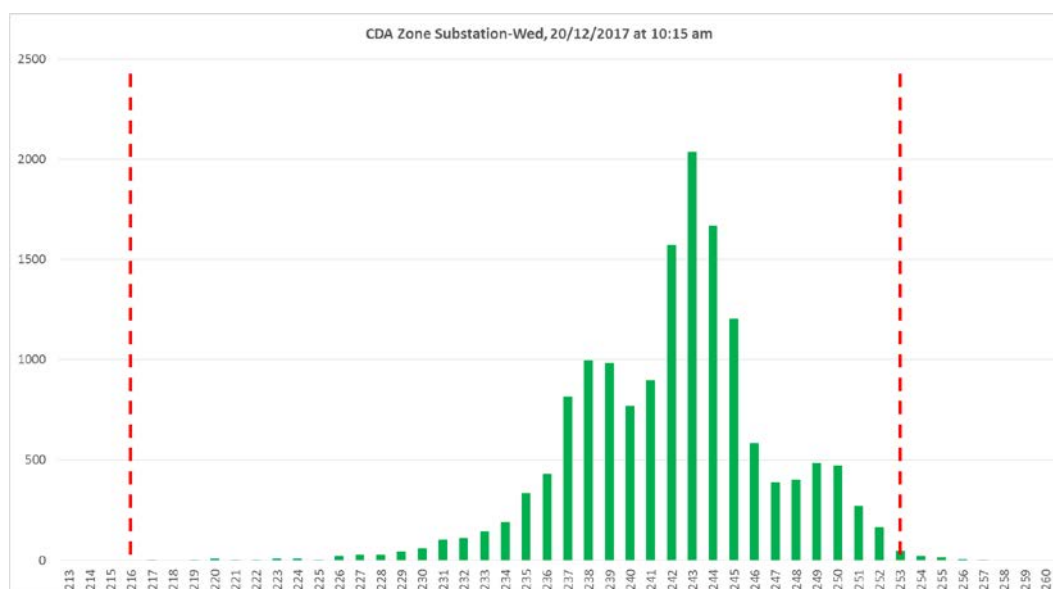


Figure 32 Customers' Voltage Profiles for CDA Zone Substation at 10:15 am on Wednesday, 20/12/2017 (DVMS in Enabled-Auto and Running in $V_{99\%}$ and Bus-Tie Circuit Breaker Closed)

Since the NAP voltage recommendations were sent to the Master transformer (Tx #1) only, opening the bus-tie circuit breaker caused the Follower transformer (TX#2) started reverting back to the default set-point of 22.59kV. Therefore, TX #1 and TX #2 were running at different tap levels of 3 and 7, respectively. It should be noted as a result of opening the bus-tie circuit breaker, the zone substations transformers were operating in Auto-



Independent mode and this is the reason why the Follower transformer started tapping up. Figure 33 shows how tapping up TX #2 caused more non-compliance customers.

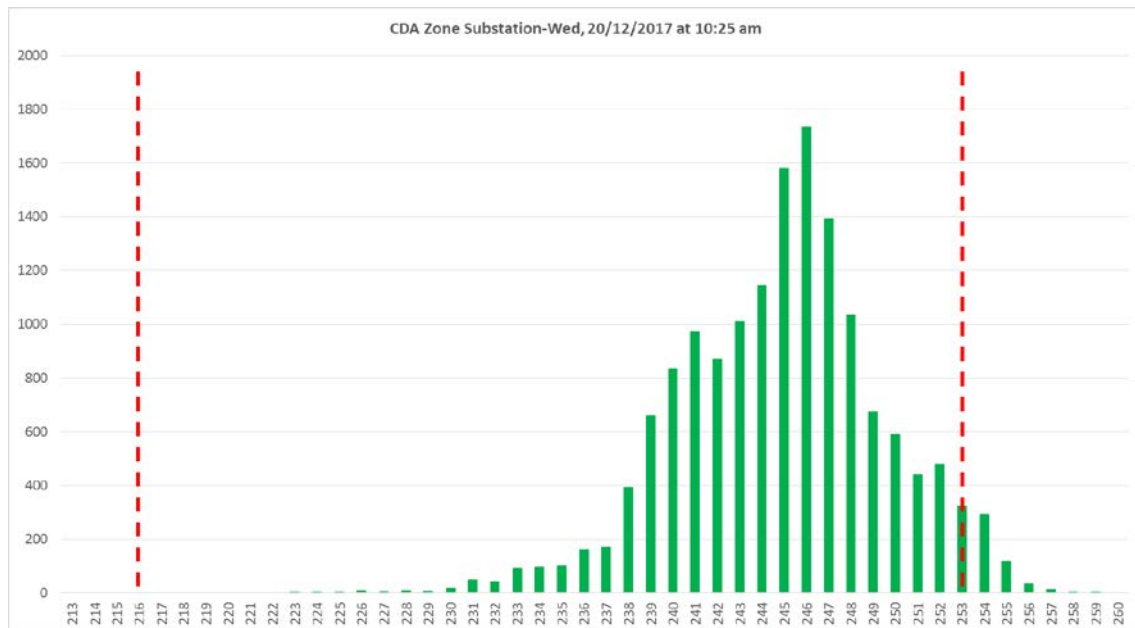


Figure 33 Customers' Voltage Profiles for CDA Zone Substation at 10:25 am on Wednesday, 20/12/2017 (DVMS in Enabled-Auto and Running in V_{99%} and Bus-Tie Circuit Breaker Opened)

In order to compare the impact of DVMS on customer's voltage level in different scenarios, V_{1%}, V_{50%} and V_{99%} values are summarised in Table 9.

Table 9: Impact of Opening Bus-Tie Circuit Breaker on Dynamic Voltage Management System

Parameter	Prior to Opening Bus-Tie Circuit Breaker		Post Opening Bus-Tie Circuit Breaker
	(DVMS Disabled) 10:00 am	(DVMS Enabled) 10:15 am	10:25 am
V _{1%}	235V	230V	233V
V _{50%}	248V	243V	245V
V _{99%}	257V	252V	255V

Figure 34 and Figure 35 also illustrate the trend for the bus voltages and tap positions of the transformers at CDA zone substation during this test.

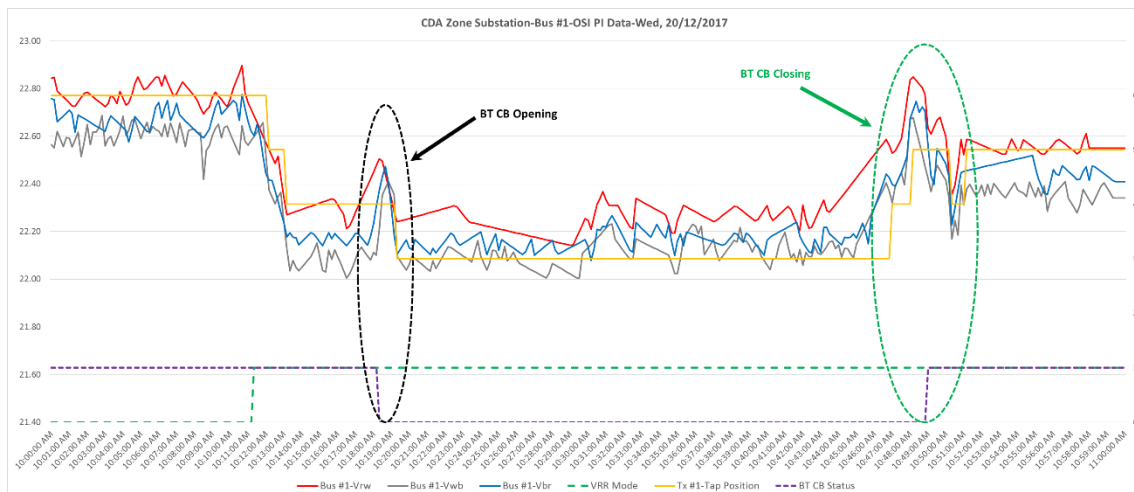


Figure 34 Impact of Opening Bus-Tie Circuit Breaker on Voltage Bus #1 and Tap Position of Transformer #1 at CDA Zone Substation while DVMS is Operating – Wednesday, 20/12/2017

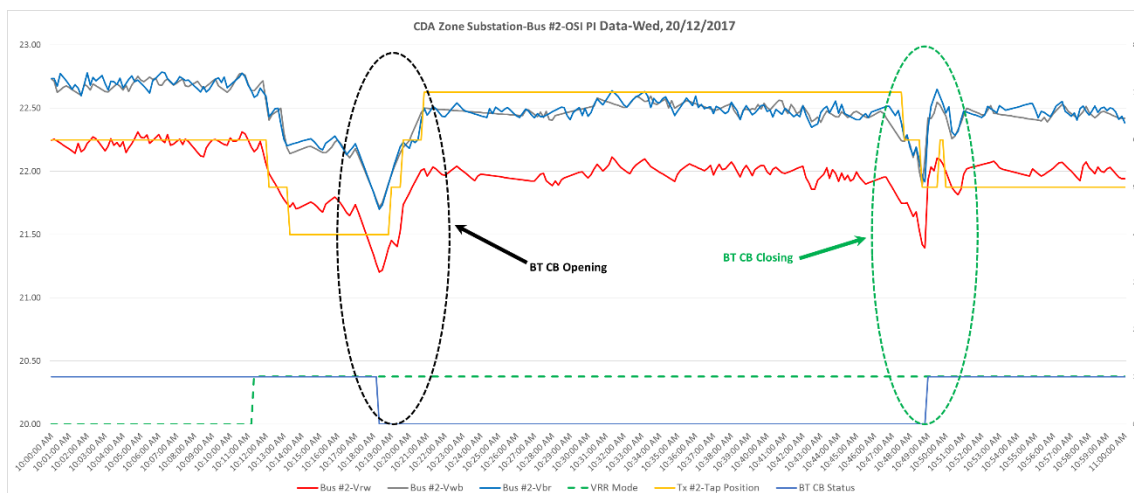


Figure 35 Impact of Opening Bus-Tie Circuit Breaker on Voltage Bus #2 and Tap Position of Transformer #2 at CDA Zone Substation while DVMS is Operating – Wednesday, 20/12/2017

The sequence of the above switching is as below:

1. Both VRRs were set in Auto mode;
2. The bus-tie circuit breaker was opened and therefore:
 - Both VRRs moved to Independent-Auto mode; and
 - SCADA point “In Independent” changed to “High” on both transformers.
3. Each VRR was set to Manual mode via MOSAIC SCADA and as a result:
 - Both VRRs moved to Independent-Manual mode; and
 - SCADA point “In Independent” changed to “High” on both transformers.
4. The bus tie circuit breaker was closed and consequently:
 - The Master transformer (Tx #1) moved to Master-Manual while the Follower transformer (Tx #2) remained in Independent-Manual mode; and
 - SCADA point “In Independent” changed to “High” on Tx #2 and remained “Low” on Tx #1.
5. Each VRR was set to Auto via MOSAIC SCADA and therefore:
 - Tx #1 moved to Master-Auto mode while Tx #2 moved to Follower mode; and



to SDVMA for process. However, due to a defect in the NAP algorithm, no recommendations were sent out to the field VRR and hence, both transformers reverted back to the default set-point. This issue is being investigated by Network Intelligence team and will be rectified shortly.

Therefore, it is recommended to disable the DVMS scheme prior to performing any switching in the distribution network.

After closing the circuit breaker of Tx #1, the second transformer was disconnected from the 22kV bus. Since Tx #2 is the Follower transformer, this switching didn't impact the NAP voltage recommendations and TX #1 was still receiving the NAP voltage recommendations from SDVMA. As a result, DVMS continued operating in Enabled-Auto and in $V_{99\%}$ mode properly. Figure 37 and Figure 38 show the impact of opening the transformer circuit breakers on bus voltages and tap positions of the transformers at CDA zone substation, respectively.

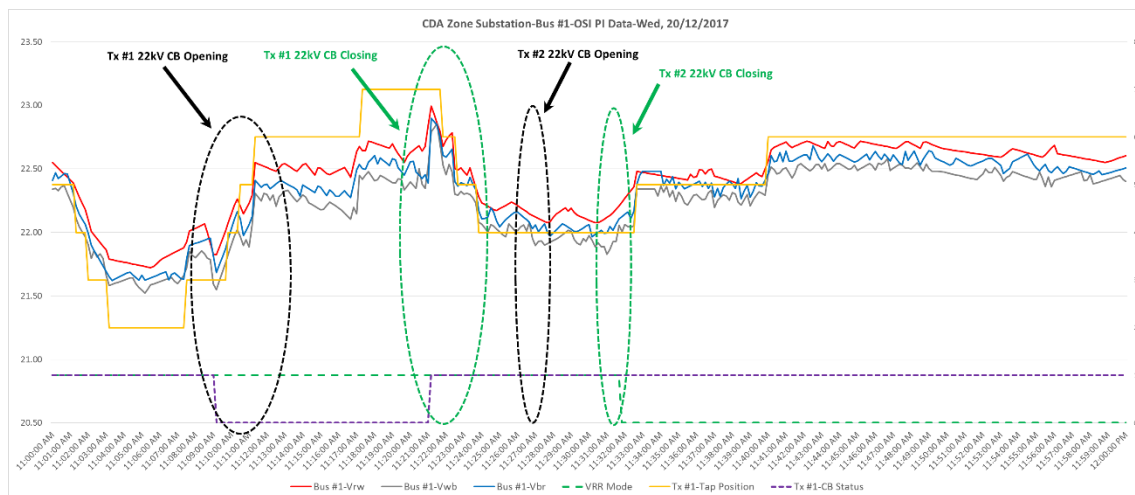


Figure 37 Impact of Opening 22kV Transformer Circuit Breakers on Voltage Bus #1 and Tap Position of Transformer #1 at CDA Zone Substation while DVMS is Operating – Wednesday, 20/12/2017

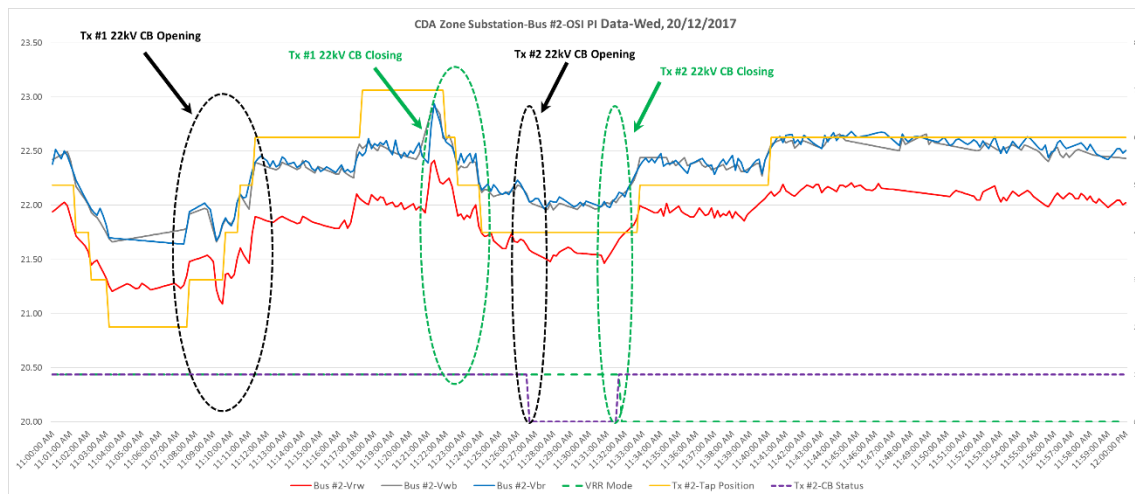


Figure 38 Impact of Opening 22kV Transformer Circuit Breakers on Voltage Bus #2 and Tap Position of Transformer #2 at CDA Zone Substation while DVMS is Operating – Wednesday, 20/12/2017

The customers' voltage profiles for each operating condition are shown in Figure 39, Figure 40 and Figure 41. As expected, before opening the circuit breaker of Tx #1, most of the customers were receiving a voltage level in compliance with the Code limits.

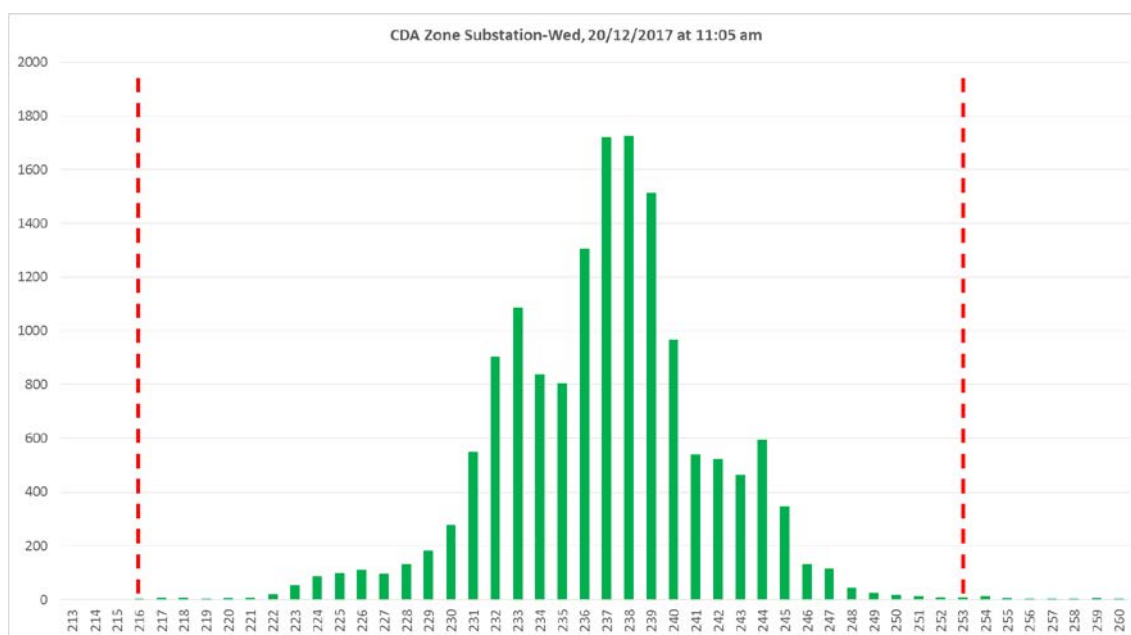


Figure 39 Customers' Voltage Profiles for CDA Zone Substation at 11:05 am on Wednesday, 20/12/2017 (DVMS in Enabled-Auto and Running in $V_{99\%}$ and Circuit Breakers of Both Transformers Closed)

By opening the 22kV circuit breaker of Tx #1, both transformers started tapping up and consequently, the voltage levels of some customers were moved to a level higher than the Code level of 253V as demonstrated in Figure 40.

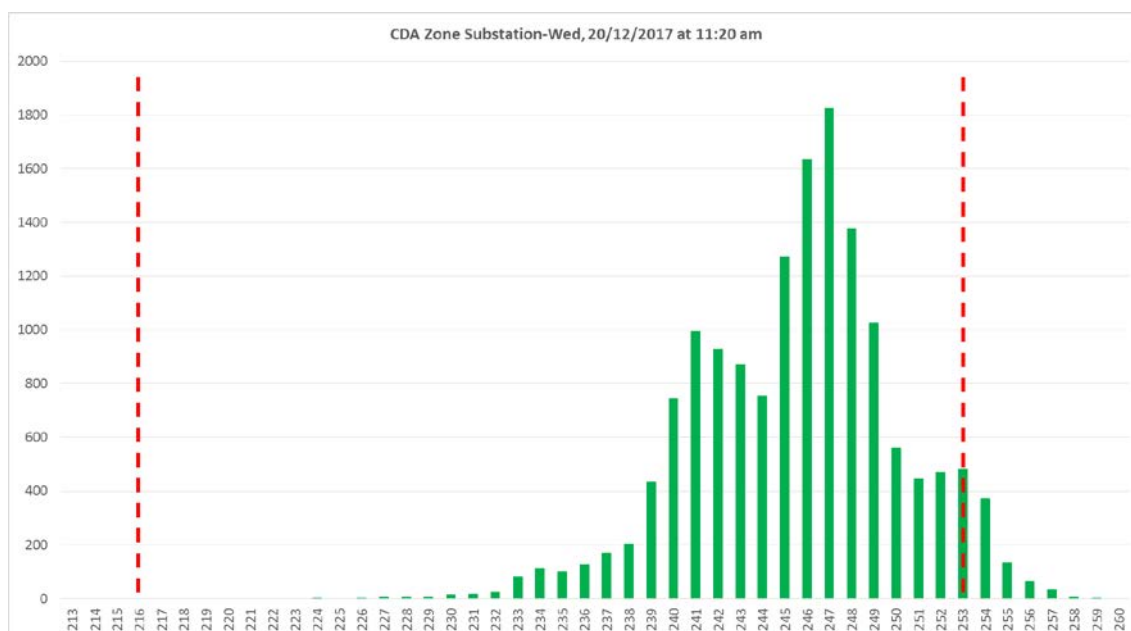


Figure 40 Customers' Voltage Profiles for CDA Zone Substation at 11:20 am on Wednesday, 20/12/2017 (DVMS in Enabled-Auto and Running in $V_{99\%}$ and Circuit Breaker of Tx #1 Opened)

In comparison, opening the circuit breaker of TX #2 (the Follower transformer) did not have an impact on the customer's voltage level and the compliance status was similar to the operating condition in which both transformers were supplying loads. This operating condition is shown in Figure 41.

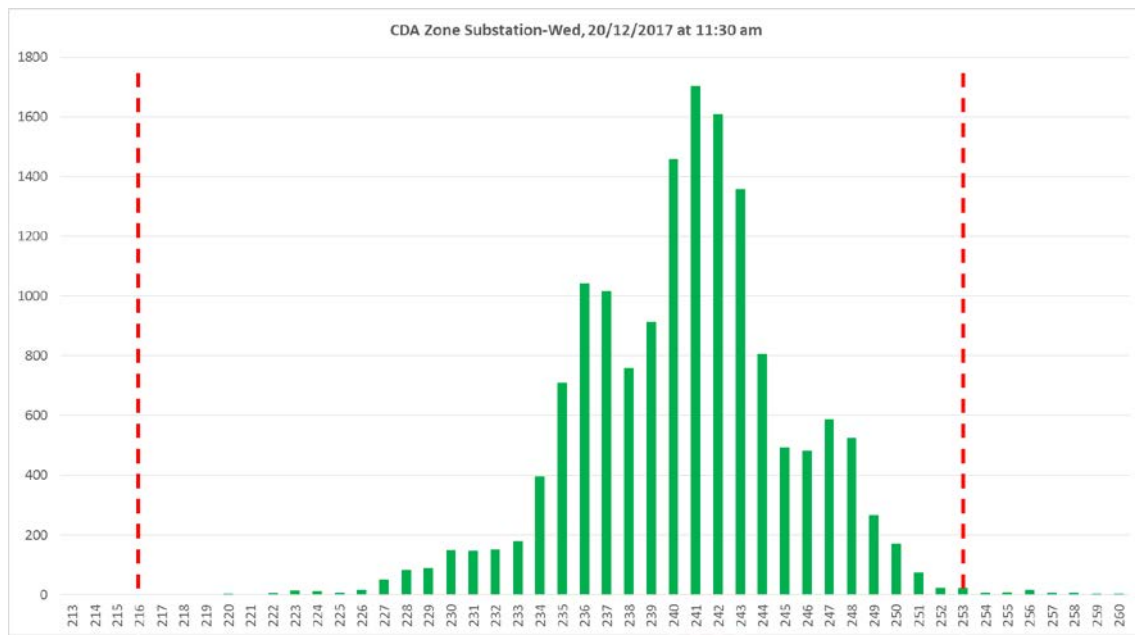


Figure 41 Customers' Voltage Profiles for CDA Zone Substation at 11:30 am on Wednesday, 20/12/2017 (DVMS in Enabled-Auto and Running in V_{99%} and Circuit Breaker of Tx #2 Opened)

In order to compare the impact of DVMS on customer's voltage level when the circuit breakers of zone substation are opened, V1%, V50% and V99% values for each scenario are calculated and summarised in Table 10.

Table 10: Impact of Opening Zone Substation Transformer Circuit Breaker on Dynamic Voltage Management System

Parameter	Prior to Opening Transformer Circuit Breaker	Post Opening Circuit Breaker of Master Transformer	Post Opening Circuit Breaker of Follower Transformer
	(DVMS Enabled) 11:05 am	(DVMS Disabled) 11:20 am	(DVMS Enabled) 11:30 am
V _{1%}	224	233	228
V _{50%}	237	246	241
V _{99%}	247	255	251

As expected, opening the circuit breaker of Master transformer and consequently, disabling DVMS resulted in more non-compliant customers.

1.1.1.3 Performance of DVMS when HV Feeder is transferred from/to Zone Substation

In order to evaluate the impact of transferring loads from/to a zone substation when DVMS is operating, the customers supplied by HT1 and CDA22 were switched to CDA and Heatherton (HT) zone substations, respectively. This test was conducted on Thursday, 21st December 2017. First, the load supplied by HT1 was transferred to CDA22 by making a parallel on CDA22 and HT1 and then opening the HT1 circuit breaker. During this test, DVMS was running in Enabled-Auto and in V_{99%} mode. Therefore, NAP was generating the voltage recommendations based on this assumption that the transferred loads to HT1 were still being supplied by CDA22. Figure 42 and Figure 43 demonstrate the customers' voltage profiles supplied by CDA prior to and post opening the HT1 circuit breaker.

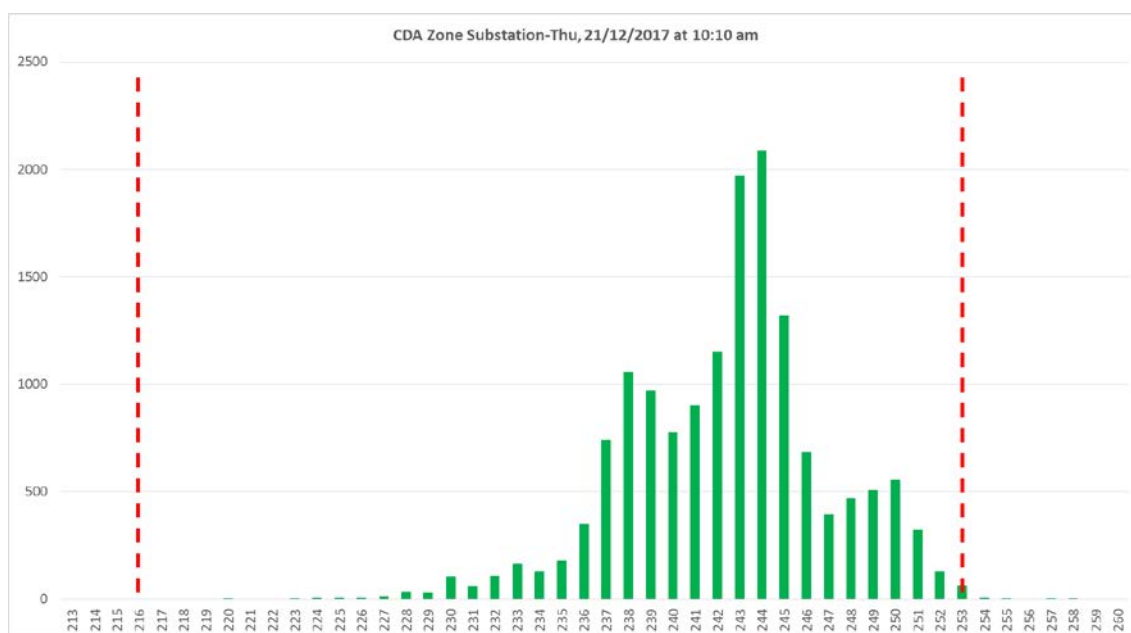


Figure 42 Customers' Voltage Profiles for CDA Zone Substation at 10:10 am on Thursday, 21/12/2017 (DVMS in Enabled-Auto and Running in V_{99%} and Circuit Breakers of CDA22 & HT1 Closed)

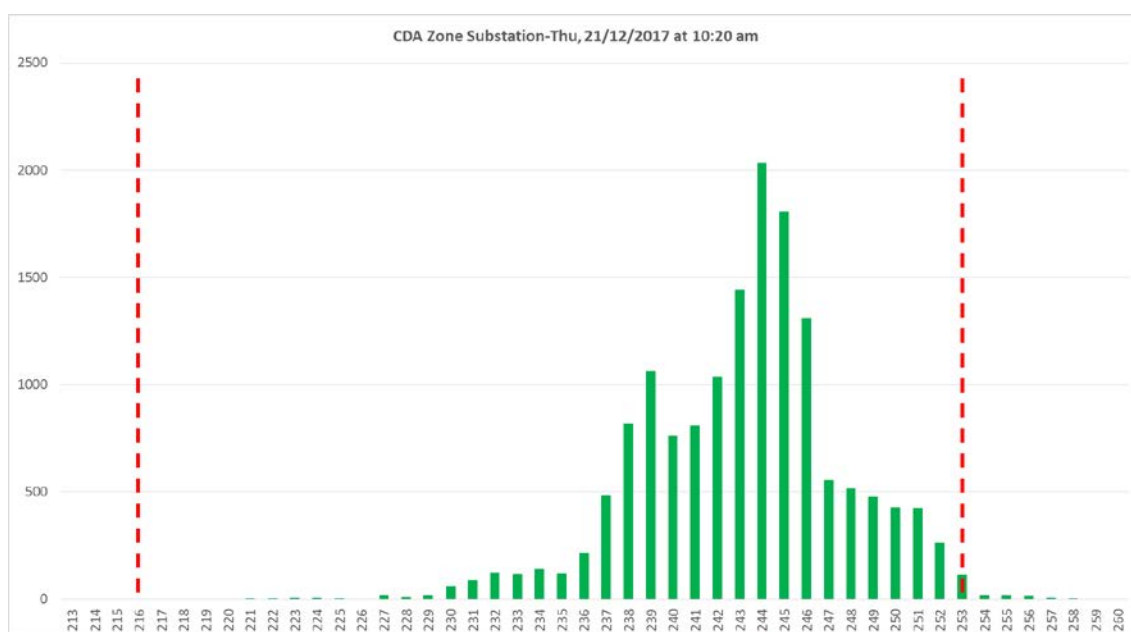


Figure 43 Customers' Voltage Profiles for CDA Zone Substation at 10:20 am on Thursday, 21/12/2017 (DVMS in Enabled-Auto and Running in V_{99%}; Circuit Breaker of CDA22 Closed and Circuit Breaker of HT1 Opened)

According to these figures, an increase in number of customers receiving voltages within the 245-250V and 228-232 ranges can be observed. The latter customers are presumed to be the ones supplied by CDA22 that is now more heavily loaded. While CDA zone substation is lightly loaded, the generated NAP voltage recommendation is not compromised. Within a heavier load situation while the NAP algorithm is in optimisation mode, there is a possibility that these customers would cause a higher voltage recommendation for the normal operating customers supplied by CDA zone substation.



After closing CDA22, the circuit breaker of HT1 was opened. The LV histogram for the customers supplied by CDA zone substations experienced two changes. Figure 44 shows this operation condition.

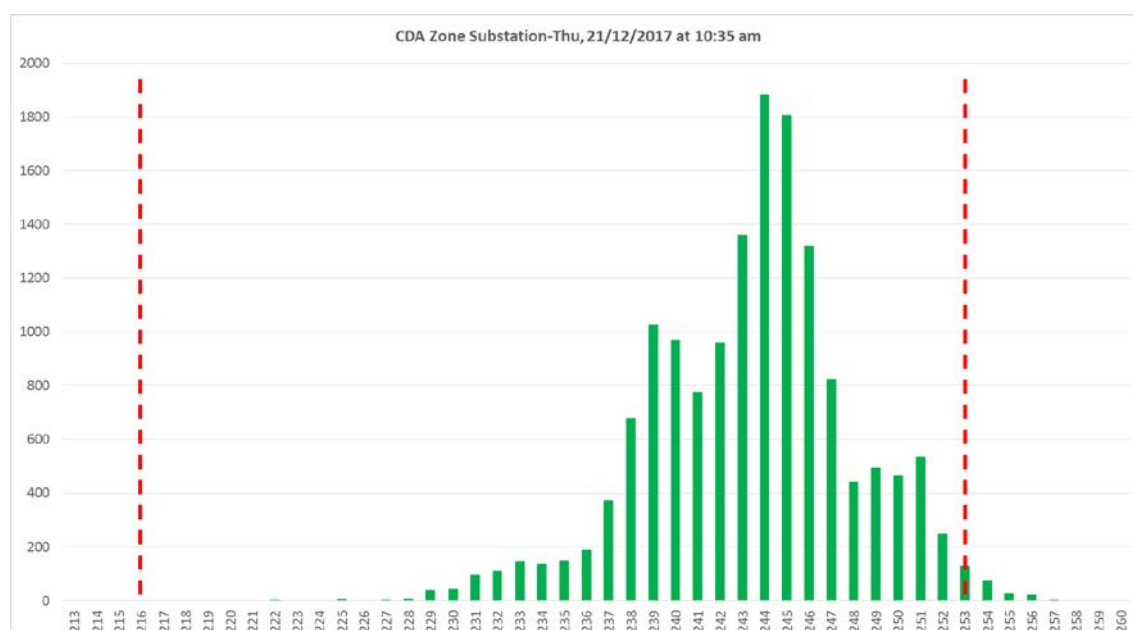


Figure 44 Customers' Voltage Profiles for CDA Zone Substation at 10:35 am on Thursday, 21/12/2017 (DVMS in Enabled-Auto and Running in V_{99%}; Circuit Breaker of CDA22 Opened and Circuit Breaker of HT1 Closed)

As this figure demonstrated, the voltage histogram as a whole increased in voltage levels delivered to the customers and therefore, V_{99%} increased but was still within the Code limit of 253V. An increased number of customers receiving voltages within the 230-233V range can also be noticed. The overall increase in voltage levels was due to the lower load on CDA zone substation. CDA22 was supplying approximately 1/6th of the zone substation load and hence, this decrease allowed the voltage to float higher.

The set-point proposed by the NAP voltage recommendation was not reduce however, a larger drop in load would have triggered this.

The increase in number of customers with lower voltage level were likely to be the once supplied by CDA22 that were fed from HT1 at the time. Since this feeder was significantly longer than the original CDA feeder therefore, this impact was expected. The NAP voltage recommendation still stayed unchanged in this abnormal operating condition. In the case that both zone substations are heavily loaded, there could be a chance that the zone substation controlled by DVMS would be in optimisation mode and the transferee zone substation would have feeders with lower voltages at the tails of the voltage histogram. In this case, incorrect NAP voltage recommendations would propose to tap up transformers at the controlled zone substation.

Figure 22 summarises the impact of transferring loads from/to CDA zone substation on performance of DVMS. According to this table, no impacts can be observed on the percentile values for voltages of transferee and transferrer zone substations.

Table 11: Impact of Transferring HV Feeders from/to Zone Substations on Dynamic Voltage Management System

Parameter	Prior to Load Transfer from HT to CDA (10:10 am)		Post Load Transfer from HT to CDA (10:20 am)		Post Load Transfer from CDA to HT (10:35 am)	
	CDA	HT	CDA	HT	CDA	HT



Parameter	Prior to Load Transfer from HT to CDA (10:10 am)		Post Load Transfer from HT to CDA (10:20 am)		Post Load Transfer from CDA to HT (10:35 am)	
	CDA	HT	CDA	HT	CDA	HT
V1%	230V	230V	231V	232V	231V	233V
V50%	243V	240V	244V	243V	244V	243V
V99%	252V	248V	253V	251V	253V	251V

Figure 45 and Figure 46 demonstrate the trend for the bus voltages and transformer tap position of CDA zone substation during this test. These figures confirm that the load transfer did not have any significant impacts on the bus voltages and transformer tap positions of CDA zone substation.

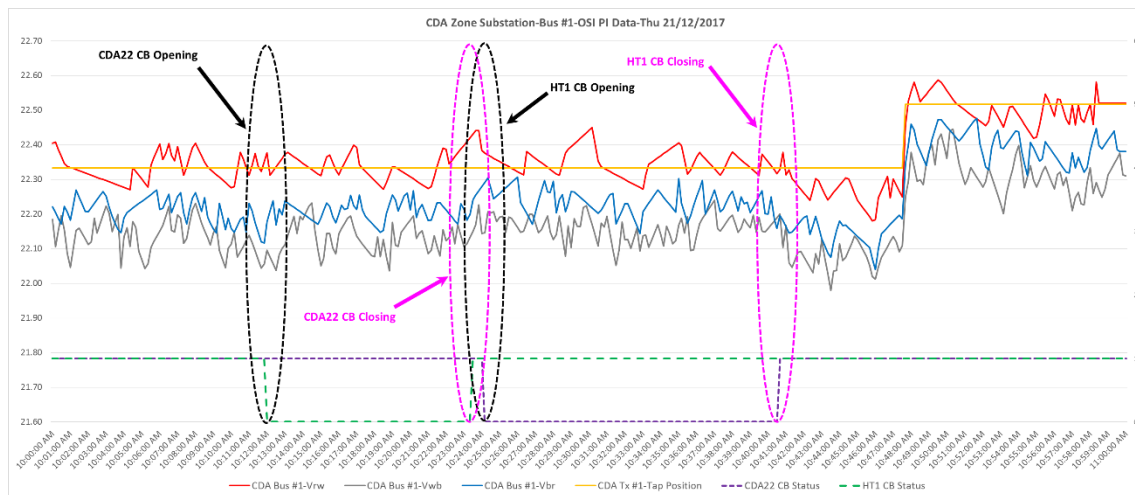


Figure 45 Impact of Opening 22kV Circuit Breakers of CDA22 and HT1 on Voltage Bus #1 and Tap Position of Transformer #1 at CDA Zone Substation while DVMS is Operating – Thursday, 21/12/2017

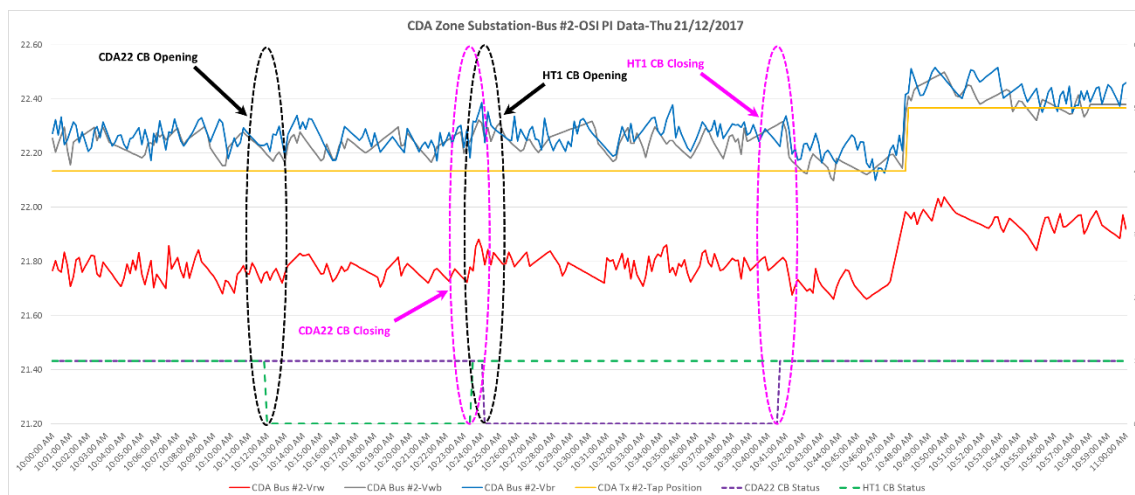


Figure 46 Impact of Opening 22kV Circuit Breakers of CDA22 and HT1 on Voltage Bus #2 and Tap Position of Transformer #2 at CDA Zone Substation while DVMS is Operating – Thursday, 21/12/2017



Figure 47, Figure 48 and Figure 49 also show the impact of load transfer on the bus voltages and transformer tap positions of HT zone substation. As expected, the load transfer did not have any significant impacts on performance of HT zone substation either.

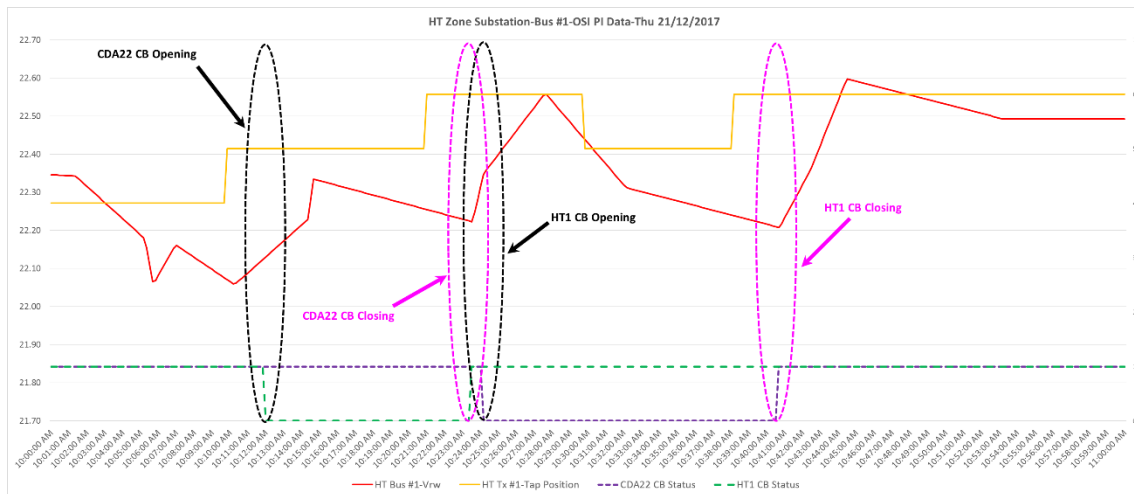


Figure 47 Impact of Opening 22kV Circuit Breakers of CDA22 and HT1 on Voltage Bus #1 and Tap Position of Transformer #1 at HT Zone Substation while DVMS is Operating – Thursday, 21/12/2017

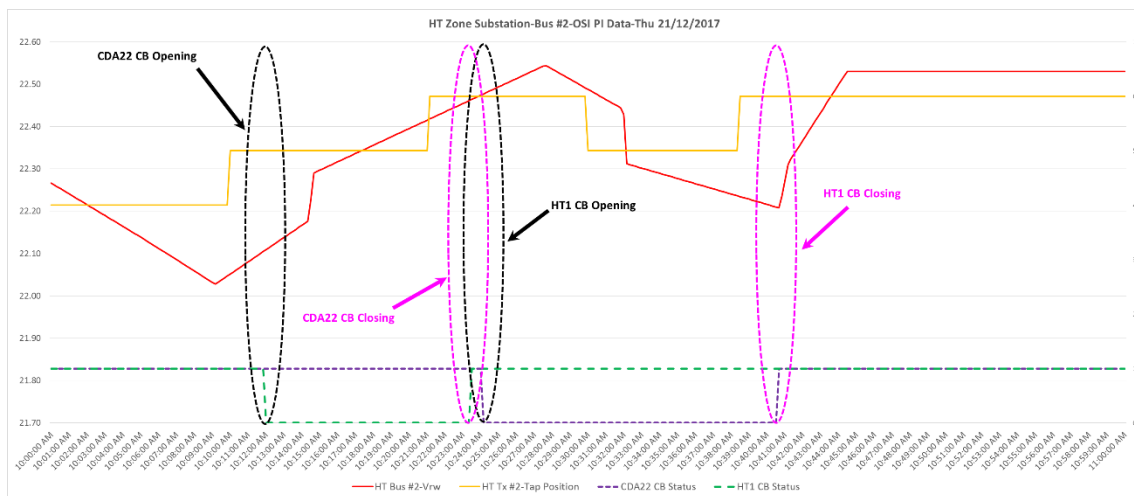


Figure 48 Impact of Opening 22kV Circuit Breakers of CDA22 and HT1 on Voltage Bus #2 and Tap Position of Transformer #2 at HT Zone Substation while DVMS is Operating – Thursday, 21/12/2017

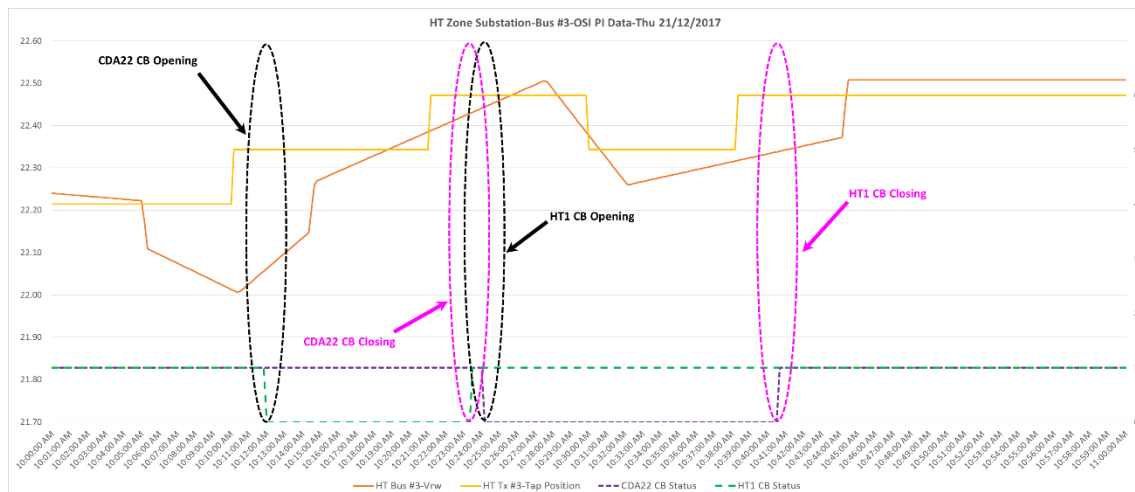


Figure 49 Impact of Opening 22kV Circuit Breakers of CDA22 and HT1 on Voltage Bus #3 and Tap Position of Transformer #3 at HT Zone Substation while DVMS is Operating – Thursday, 21/12/2017

1.1.1.4 Performance of DVMS when VRRs are switched to Manual Mode

To validate the performance of DVMS when the field VRRs operate in Manual mode, both VRRs at CDA zone substation were remotely switched to Manual mode by NCC on Wednesday, 20th December 2017 and also Thursday, 21st December 2017. Consequently, both VRRs moved to Independent Manual mode as the bust-tie circuit breaker was opened at the time of testing. It was observed that each VRR changed the tap settings of the associated transformer independently and if the operator changes the tap for the Master transformer, the tap for the Follower transformer will not be changed or vice versa. In other words, when moving from Auto to Manual mode, the voltage set-point becomes irrelevant as the VRR is no longer performing any voltage regulation functionality.

1.1.1.5 Performance of DVMS when VRRs are switched to Local Mode

By switching the VRRs to Local mode, as expected, no actions was be taken by the VRRs and they remained at the last tap set-points. The Local mode of VRRs did not affect the operation of NAP and the NAP voltage recommendations were still being generated.

Figure 50 demonstrates both Local and Remote (SCADA) operating modes of DR-E3. Initially, DR-E3 was supposed to revert back to the default voltage set-point but after UE requested to Dynamic Rating to modify the firmware to minimise the associated health and safety risk, DR-E3 will stop changing the tap when it is switched to Local mode.

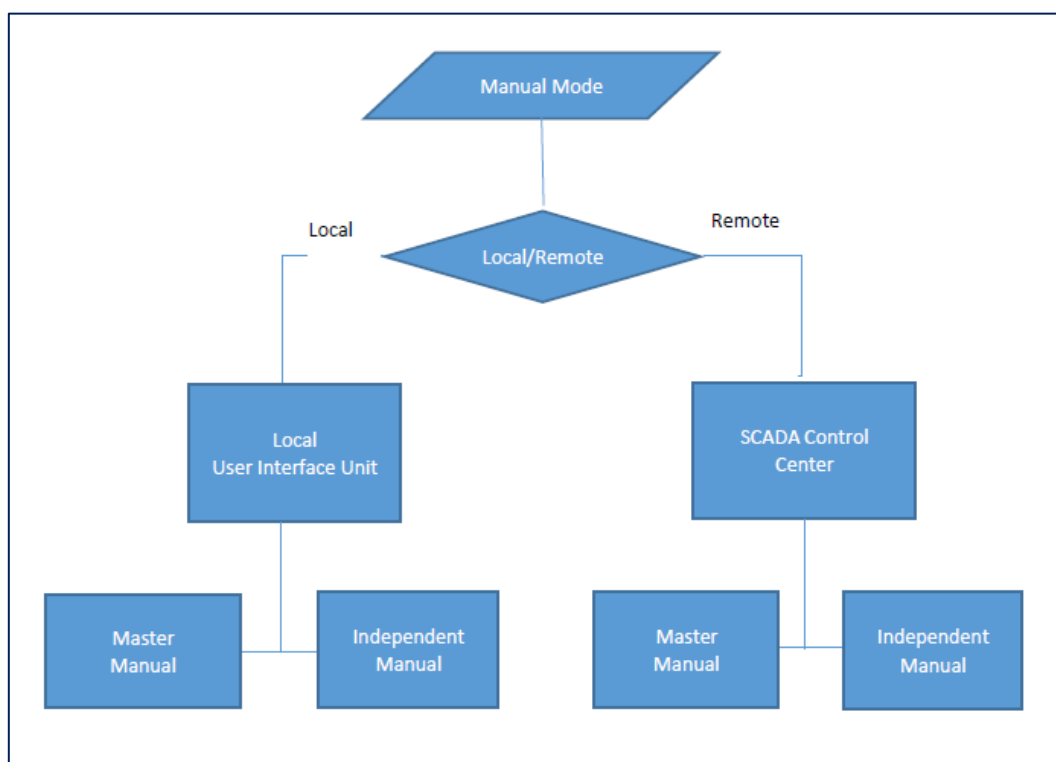


Figure 50 Local and Remote Control Implemented in DR-E3

1.1.1.6 Performance of DVMS when Emergency Voltage Set-Points are selected

Similar to DRMCC-T3, DR-E3 does not interlock emergency voltage set-points for Local and Remote modes. The emergency voltage set-points can be controlled via SCADA in either mode. However, interlock has been added against SCADA controls for emergency voltage set-points to only allow the control to be sent when the VRR is in default or emergency voltage set-points and not when in any dynamic voltage set-point. This functionality was tested and no actions were taken by DVMS when it was running in Enabled-Auto mode and emergency voltage set-points were selected.

1.1.1.7 Performance of DVMS when it is running in Enabled-Auto mode and VRRs are switched to Manual Mode.

In order to test the performance of DVMS while it is running in Enable-Auto mode and VRR are switched to Manual and then to Auto mode, a test was conducted on Tuesday, 30th January 2018. For this test, the below order was followed:

- Enable DVMS, run it in Enabled-Auto and V99% mode and then allow to stabilise;
- Switch the VRRs to Manual mode while DVMS is running in Enabled-Auto and V99% mode;
- Tap up the transformers manually and monitor the voltage set-points generation by NAP;
- Observe the SDVMA response while it receives the new voltage recommendations from NAP;
- Switch back the VRRs to Auto and monitor the voltage set-points generation by NAP; and
- Observe the SDVMA response while it receives the new voltage recommendations from NAP.

As expected, switching the VRRs to Manual mode did not result in any changes on the transformer tap settings at CDA zone substation. After that, the transformers were manually tapped up from level 4 to 5 and then 6. The next few recommendations were correct based on the voltage histogram.

Since VRRs were operating in Manual mode, the NAP voltage recommendations were not accepted by the Master VRR. Consequently, when the VRRs were switched back to Auto mode, the active voltage set-points in VRRs were the ones had been set before switching the VRRs to Manual mode.

No runaway situation was observed in this test case as NAP is bound to ± 1 step from the last voltage set point. This is correct behaviour. However, there might be a potential risk due to the same behaviour. In the case that the



voltage is close to a tap change and transformers are manually changed significantly, it would be expected to see an incorrect voltage set-point change, either into or away from the risky zone.



3.4. Learnings

According to the performance of the DVMS trial at CDA zone substation up to date, there are a number of recommendations as listed below that by taking them into consideration, UE can improve the effectiveness of this scheme for the rollout.

3.4.1. Modify Default Voltage Set-Points at Zone Substations

Since the default voltage set-points of VRRs have typically been selected based on high network loading conditions on the distribution network, they are relatively higher than the nominal voltages. This has been resulted in over-voltages received by the customer most of the time when the network load is not very high.

Once DVMS is operational at all of the zone substations, the default voltage set-points will be used only when there is a network abnormal operating condition such as opening the bus-tie circuit breaker. Due to the design of DVMS by disabling the scheme, the transformers will revert back to the default voltage set-points and they might need to perform a few tap changes.

Therefore, to minimise the number of tap changes as a result of this switching, it is recommended to modify the values of default voltage set-points to the most common dynamic voltage set-points. In that case, if a bus-tie circuit breaker is opened, a tap change will not be required in most of the time. It would reduce the risk of shortening the life of OLTCs.

It should be noted that the new values for the default voltage set-points shall be selected after analysing the smart meter data for the zone substation.

3.4.2. Reduce the Step between Dynamic Voltage Set-Points

Since DVMS has been trialled for the first time on the UE distribution network, 2.5% was selected as the step between dynamic voltage set-points at the time of commissioning. Based on the tests conducted on the trial, it is recommended to revisit this step and also the voltage settings before rolling out the scheme on the network. It is expected that a smaller step (e.g. 1.5%-2%) would assist NAP to generate smoother voltage recommendations and as a result, manage the voltage swells and sags due to switching of terminal station/zone substation capacity banks. Consequently, this modification would improve the performance of DVMS.

3.4.3. Proceduralise Network Abnormal Operating Conditions

In some network abnormal operating conditions, it would be easier to disable the DVMS scheme manually prior to performing any switching. In this way, the unnecessary complications imposed to the NAP algorithms would be avoided. Therefore, the relevant operating procedures should be updated to include the instructions for the Controllers on how to disable the system.

However, Network Intelligence team plan to improve the NAP algorithms to accommodate network abnormal operating conditions in future. Thus, until the modified algorithms are successfully tested and implemented, it is recommended to proceduralise these operating conditions for DVMS.

3.4.4. Develop a Switch to Change Operating Modes of DVMS

Currently, in order to switch the operating modes of DVMS (from $V_{99\%}$ to $V_{1\%}$ and vice versa), a Service Desk request should be raised and it will take a few days (minimum 1 day if escalated) to complete the task. While based on the funding agreement between UE and ARENA, DVMS shall be switched from $V_{99\%}$ to $V_{1\%}$ in 10 minutes for demand response purposes.

Therefore, it is strongly recommended to modify SDVMA and NAP so that a switch can be developed in MOSAIC SCADA for the Controllers to switch the operating modes of DVMS in a prompt way.

One option would be that NAP sends two voltage recommendations for both modes of $V_{99\%}$ and $V_{1\%}$ to SDVMA simultaneously and based on the status of mode switch (defined by the Controller), the appropriate NAP voltage recommendation will be considered by SDVMA and sent out to the field VRR.

All options including this need to be discussed with the stakeholders to identify the least-cost technically acceptable one.



3.4.5. Send Recommendations to Each VRR

DVMS currently sends the NAP voltage recommendations to the Master relays only. It has been confirmed with Dynamic Ratings that it is feasible to send the NAP voltage recommendations to all of the relays including the Followers at zone substations without any modifications on the current firmware. This would improve the performance of DVMS especially when a bus-tie circuit breaker is open by the Controller.

Based on the conducted tests once the bus-tie circuit breaker is opened, the Follower transformer start changing the tap and might create some circulating currents between the transformers and result in detrimental impacts. The reason for this behaviour is during normal operating conditions, the Follower VRRs follow the Master VRR and will change the transformer taps but the actual set-points in the Follower relays are not changed as the Follower VRRs do not receive the NAP voltage recommendations.

Then, when the Follower VRRs are switched to Independent mode as a result of opening the bus-tie circuit breaker, they revert back to the set-point they were at before running in Master-Follower that could be different from the current voltage set-point of the Master VRR.

By sending NAP voltage recommendations to each relays, the Master VRR will consider the control command and act accordingly while the Follower relays will only change the voltage set-points internally but at the same time follow the Master VRR.

The cost of this option need to be evaluated and discussed with the key stakeholder before proceeding as it might be costly due to the need for conducting comprehensive tests.

3.4.6. Revisit the Settings of VRR Timeout Deployed in Failsafe Function

The current settings for the VRRs at CDA zone substation are set at 30 minutes. It means in case of losing communications between the Master VRR and DVMS, the transformers will revert back to the default voltage set-points in 30 minutes. It would be worthwhile to revisit this setting before rolling out the scheme on the network to ensure an optimum value is chosen.

It should be noted that all of the required modifications on VRRs need to be discussed with both manufacturer: Dynamic Ratings and A. Eberle to ensure all relays on the UE distribution network are capable of performing the new functionalities.

3.4.7. Customise the Limits for $V_{1\%}$ and $V_{99\%}$

It will be beneficial for UE to have the limits for both operational modes of $V_{1\%}$ and $V_{99\%}$ customisable.

3.4.8. Improve the NAP Algorithms

The calculation of the voltage set-points for a zone substation will be based on historical data received from all of the smart meters serviced by that zone substation.

3.4.9. Retain the Emergency Voltage Set-Points in Final Solution

Since one of the business requirements for VRRs is to retain the functionalities of DRMMC-T3, it is recommended to retain the emergency voltage set-points (E1 & E2) in the final scheme. Therefore, if demand reduction is required while the DVMS is not available due to maintenance or loss of communication from NAP, the Controllers will be able to manage the demand on the network via reducing the voltage at zone substations.

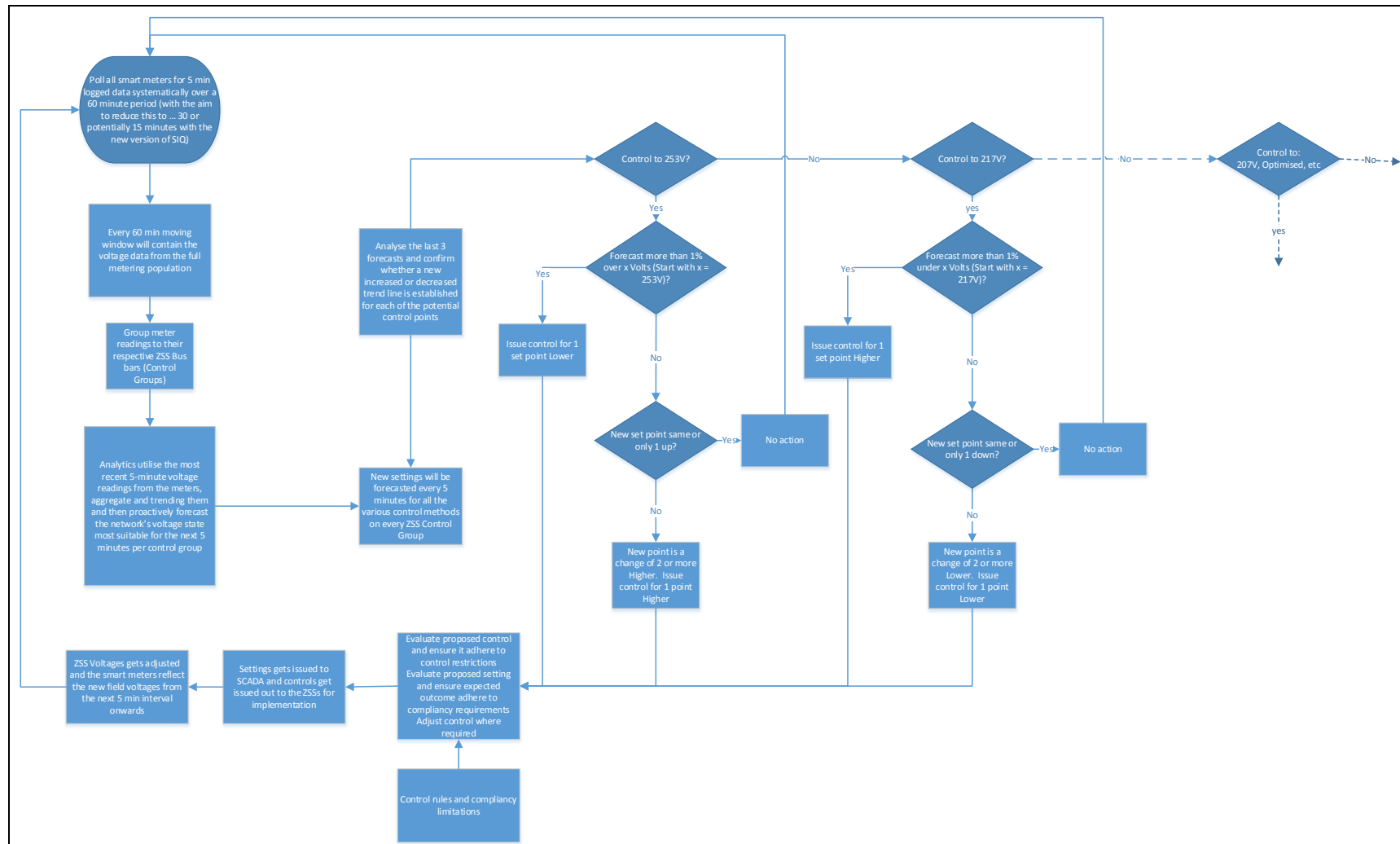
3.4.10. Remain the DVMS at CDA Zone Substation Operational

According to the test results and also the performance of the DVMS at CDA zone substations, it can be concluded that the trial has been successful. Therefore, it is strongly recommended to remain the scheme in Production and operational.

Since more customers supplied by CDA zone substation receive a voltage level compliant with the Code limits as a result of operating the DVMS, UE will receive by far less voltage complaints from the customers. More Controllers will also have this opportunity to work with the scheme and familiarise themselves with the new functionalities of the scheme.



3.5. NAP Algorithms deployed in DVMS





3.6. Business Requirements for the Voltage Regulating Relays (DR-E3 and REG-D)

No	Requirement	Description	Implementation
VRR_1	During normal operation (automatic or manual) and the bus-tie circuit breaker is closed , in case of partial/complete loss of or delay in communications between smart meters in field (SensorIQ) and NAP (at least data for 10% of the meter population for the selected zone substation shall be available), DVMS shall halt the process for all of the affected zone substations.	SDVMA shall raise an alarm and end the SDVMA capability when the NAP heartbeat is either shutdown/failed. The NAP heartbeat will be shutdown/failed if SensorIQ communications is failed. SDVMA in the process will send controls to the field VRRs to return to the default voltages set-points before the application exits.	The associated VRRs (Master and the Followers) shall return to the default voltages set-points.
VRR_2	During normal operation (automatic or manual) and the bus-tie circuit breaker is opened , in case of partial/complete loss of or delay in communications between smart meters in field (SensorIQ) and NAP (at least data for 10% of the meter population for the selected zone substation bus shall be available), DVMS shall halt the process for all of the affected zone substations.	SDVMA shall raise an alarm and end the SDVMA capability when the bus-tie circuit breaker is <u>opened</u> . NAP shall cease providing voltage recommendations to the impacted zone substation. SDVMA shall interlock any controls going out to the impacted zone substation.	Controller shall manually disable the system and consequently, the VRRs will revert back to the default voltages set-points.
VRR_3	During normal operation (automatic or manual) and the bus-tie circuit breaker is closed , in case of partial/complete loss of or delay in communications between NAP and SDVMA in MOSAIC SCADA, DVMS shall halt the process for all of the affected zone substations.	SDVMA shall raise an alarm and end the SDVMA capability when the NAP heartbeat is either shutdown/failed. The NAP heartbeat will be shutdown/failed if communications between NAP and SDVMA is lost. SDVMA in the process will send controls to the field VRRs to return to the default voltages set-points before the application exits.	The associated VRRs (Master and the Followers) shall return to the default voltages set-points.
VRR_4	During normal operation (automatic or manual) and the bus-tie circuit breaker is opened , in case of partial/complete loss of or delay in communications between NAP and SDVMA in MOSAIC SCADA, DVMS shall halt the process for all of the affected zone substations.	SDVMA shall raise an alarm and end the SDVMA capability when the bus-tie circuit breaker is <u>opened</u> . NAP shall cease providing voltage recommendations to the impacted zone substation. SDVMA shall interlock any	Controller shall manually disable the system and consequently, the VRRs will revert back to the default voltages set-points.



No	Requirement	Description	Implementation
		controls going out to the impacted zone substation.	
VRR_5	During normal operation (automatic or manual) and the bus-tie circuit breaker is closed , in case of partial/complete loss of or delay in communications between SDVMA in MOSAIC SCADA and the RTU located at the selected zone substation, DVMS shall halt the process for the affected zone substation.	SDVMA shall raise an alarm and end the SDVMA capability when heartbeat from the VRR is either shutdown/failed. SDVMA in the process will send a control to the field VRRs to return to the default voltages set-points before the application exits.	The associated VRRs (Master and the Followers) shall return to the default voltages set-points.
VRR_6	During normal operation (automatic or manual) and the bus-tie circuit breaker is opened , in case of partial/complete loss of or delay in communications between SDVMA in MOSAIC SCADA and the RTU associated with the selected zone substation, DVMS shall halt the process for all of buses of the affected zone substation.	SDVMA shall raise an alarm and end the SDVMA capability when the bus-tie circuit breaker is <u>opened</u> . NAP shall cease providing voltage recommendations to the impacted zone substation. SDVMA shall interlock any controls going out to the impacted zone substation.	Controller shall manually disable the system and consequently, the VRRs will revert back to the default voltages set-points.
VRR_7	During normal operation (automatic or manual) and the bus-tie circuit breaker is closed , in case of partial/complete loss of or delay in communications between the RTU and the Master VRR located at the selected zone substation, DVMS shall halt the process for the affected zone substation.	The SDVMA shall raise an alarm and end the SDVMA capability where the Master VRR located at the selected zone substation does not receive a NAP voltage set-point command in the predefined time period, DVMS scheme shall raise an alarm and halt the process for the affected zone substation.	The associated VRRs (Master and the Followers) shall return to the default voltages set-points.
VRR_8	During normal operation (automatic or manual) and the bus-tie circuit breaker is opened , in case of partial/complete loss of or delay in communications between the RTU and the VRR associated with the selected zone substation bus, DVMS shall halt the process for all of buses of the affected zone substation.	SDVMA shall raise an alarm and end the SDVMA capability when the bus-tie circuit breaker is <u>opened</u> . NAP shall cease providing voltage recommendations to the impacted zone substation. SDVMA shall interlock any controls going out to the impacted zone substation.	Controller shall manually disable the system and consequently, the VRRs will revert back to the default voltages set-points.
VRR_9	During normal operation (automatic or manual) and the bus-tie circuit breaker is closed , in case of occurring a fault on the distribution network which will impact the selected substations and their feeders (resulting in voltage fluctuations), DVMS shall halt the	DVMS system shall be manually disabled when a fault occurs which will affect the selected zone substations.	Controller shall have the ability to disable the DVMS scheme for the affected zone substation via the station diagram or the tabular display in SCADA.



No	Requirement	Description	Implementation
	process for the all of the affected zone substations.		The associated VRRs (Master and the Followers) shall return to the default voltages set-points.
VRR_10	During normal operation (automatic or manual) and the bus-tie circuit breaker is opened , in case of occurring a fault on the distribution network which will impact the selected substation buses and their feeders (resulting in voltage fluctuations), the DVMS shall halt the process for the all buses of the affected zone substations.	SDVMA shall raise an alarm and end the SDVMA capability when the bus-tie circuit breaker is <u>opened</u> . NAP shall cease providing voltage recommendations to the impacted zone substation. SDVMA shall interlock any controls going out to the impacted zone substation.	Controller shall manually disable the system and consequently, the VRRs will revert back to the default voltages set-points.
VRR_11	Where the bus-tie circuit breaker is opened manually or automatically, the Master-Follower scheme is not valid anymore and each VRR at the nominated zone substation shall be treated as an independent device.	Due to switching/maintenance on the distribution network, the bus-tie circuit breaker will require to be opened and each VRR at the nominated zone substation shall operate as an independent device. SDVMA shall raise an alarm and end the SDVMA capability when the bus-tie circuit breaker is <u>opened</u> . NAP shall cease providing voltage recommendations to the impacted zone substation. SDVMA shall interlock any controls going out to the impacted zone substation.	Controller shall manually disable the system and consequently, the VRRs will revert back to the default voltages set-points.
VRR_12	Where the bus-tie circuit breaker is closed manually or automatically, the Master-Follower scheme (if applicable) is valid and all VRRs (Master and the Followers) at the nominated zone substation shall communicate with SDVMA in MOSAIC SCADA via the associated RTU.	After completing the maintenance work on the affected zone substation or clearing the occurred fault on the network of the affected zone substation, the bus-tie circuit breaker (if applicable) will require to be closed and the Master-Follower will be back into service and the NAP voltage recommendation shall be sent to all VRRs (Master and the Followers) and the Follower VRRs will follow the Master VRR.	DVMS shall utilise the voltage data directly available from the sampled smart meters (at least 10% of the population for the zone substation) for calculating the proposed voltage-set-point for all VRRs at the nominated zone substation.
VRR_13	During normal operation (automatic or manual) and the bus-tie circuit breaker is closed , DVMS shall send the NAP voltage recommendation to all VRRs	DVMS shall only take the NAP voltage recommendations into account rather than any other	DVMS shall send the NAP voltage recommendation (at least 10% of the population for the zone substation) to the



No	Requirement	Description	Implementation
	(Master and the Followers) only at the nominated zone substation without any modifications from the Controller.	systems.	associated VRRs (Master and the Followers). In Manual mode, the Controller shall only have the ability to send the NAP voltage recommendation to the associated VRRs (Master and the Followers) and not to modify the value.
VRR_14	During normal operation (automatic or manual) and the bus-tie circuit breaker is opened , DVMS shall stop sending the NAP voltage recommendations to the associated VRRs (Master and the Followers) at the nominated zone substation.	SDVMA shall raise an alarm and end the SDVMA capability when the bus-tie circuit breaker is <u>opened</u> . NAP shall cease providing voltage recommendations to the impacted zone substation. SDVMA shall interlock any controls going out to the impacted zone substation.	Controller shall manually disable the system and consequently, the VRRs will revert back to the default voltages set-points.
VRR_15	The new VRRs (DR-E3) shall remain functionally equivalent to the existing VRRs (DRMCC-T3).	As outlined in the Technical Scope of Works, the new VRRs shall have minimal functional changes in order to achieve the implementation of the DVMS. Any functionality which is not explicitly covered in this section as a requirement of the VRR and transformer management relay is assumed to be retained equivalent to the existing functionality.	The reference VRR for DR-E3 shall primarily be the DRMCC-T3 units installed at CDA zone substations. Where it is not possible to achieve the same functionality, the functionality should then be aligned to the UE implementation of the A. Eberle VRRs. Any cases for which the functionality cannot be aligned with either relay mentioned above this is considered a gap in functionality. This should be reported with a proposed solution to UE for resolution.
VRR_16	The station RTU and SCADA host shall be transparent for the purposes of the DVMS.	All required, and additional, statuses, analogues and controls for the VRRs shall be configured in the station RTU and SCADA host. Although, this remains within the business-as-usual (BAU) operation of these devices, no custom logic or functionality beyond standard tasks shall be completed by these components.	The SIOS templates shall be used to provide direction for the requirements of the SCADA Host and station RTU. This is a standard process.
VRR_17	The VRR shall incorporate a watchdog timer as a failsafe mechanism.	A configurable watchdog timer shall be available in the VRR to reset the voltage set-point to the default nominal	The failsafe action can be considered to revert to the default voltage set-point. Initially, the configurable



No	Requirement	Description	Implementation
		<p>voltage set-point if a dynamic voltage set-point control is not received in the configurable period.</p> <p>The watchdog timer shall be reset when a control to enable a DVMS voltage set-point (voltage set-point other than the default) is received. This includes a control for the voltage set-point which the VRR is already regulating to.</p> <p>Upon expiry of the watchdog timer, the relay shall enact the failsafe action. This is defined in implementation for the trial.</p> <p>When in the default, normal or emergency voltage set-point, the watchdog timer shall not take any action.</p>	<p>watchdog timer shall be set to xx seconds.</p>
VRR_18	The VRR shall have the capability to retain the last voltage set-point.	The relay shall retain the last voltage set-point when it is placed into Manual or Local voltage regulation mode.	No action shall be taken by the VRR when it is placed into Manual or Local voltage regulating mode.



4. Quantifying the sensitivity of demand to voltage changes

The direct relationship between voltage and electrical load is well known within the electricity industry for a long time. Electrical power increases and decreases when voltage is increased and decreased, respectively. However, the magnitude of change in load in response to voltage change is dependent upon the electrical characteristics of the load connected to the network at that point in time. Further, the magnitude of the acceptable voltage change is typically a narrow band as Network Service Providers (NSP) have a regulatory obligation to maintain the supply voltage to customers within certain pre-defined limits.

United Energy (UE) has used this relationship to manage the network loading, specifically in the sub-transmission systems and transmission connection assets in the event of a critical plant outage, and for generation shortfalls. UE zone substations are equipped with either one or two emergency voltage set points so that the appropriate setting can be armed as require to gain a load relief rather than load-shedding customers. Typically, the set point 1 is either -2% or -3% of float voltage and the set point 2 is either -4% or -5% of the float voltage. Even though the current UE standard for emergency voltage set points are -3% and -5%, the majority of the zone substations have legacy -2% and -4% settings. There is no urgency to update all the emergency voltage set points to match with the current UE standard, however opportunistically bringing all the set points in line with the standard values during the DVMS rollout will be beneficial.

UE presently has a panel contract with the Australian Energy Market Operator (AEMO) to provide demand response services using voltage reduction from 2017/18 summer for 3 years with grant funding from the Australian Renewable Energy Agency (ARENA) and dispatch funding from the AEMO Short Notice RERT⁸ panel.

As part of these works, the emergency voltage set points in the UE network were reviewed. This assessment identified that emergency voltage set points at 18 zone substations can be remotely activated through SCADA and settings need to be reapplied at Burwood (BW) and Surrey Hills (SH) zone substations. Further, it was identified that three more zone substations, Oakleigh (OAK), Springvale (SV) and Springvale West (SVW) zone substations are ready for emergency voltage reduction and required settings updated. Changes required at OAK were deemed to be complicated and would be addressed in the DVMS rollout programme. Therefore, it was decided to proceed with the setting updates at SV and SVW only. In addition, Notting Hill (NO) zone substation was included into the emergency voltage reduction Group Function. These changes have subsequently been actioned and now UE has 23 zone substations ready for emergency voltage reduction.

To assess the demand response performance of the network under emergency voltage reduction, three field tests were conducted on 14 November 2017 (set point 1), 20 November 2017 (set point 2) and 01 December 2017 (AEMO test 1, set point 2). The field tests indicated that the emergency set point 1 (either -2% or -3%) is practically insufficient due to the resolution of available metering to provide tangible voltage reduction and consequent demand reduction at most of the zone substations. However, the emergency set point 2 (either -4% or -5%) provides sufficient voltage reduction and noticeable demand response from the available metering. Out of 23 zone substations that are now ready for emergency voltage reduction, 13 zone substations have -4% as set point 2 and 10 zone substation are armed with -5%.

Sending SCADA commands to voltage regulating relays at zone substations that participate in emergency voltage reduction is a sequential process. The field tests indicated that SCADA commands can automatically be sent to all the participating zone substations within 3-5 minutes. However, some practical difficulties related to the tap changes are noted. Some of the transformers run out of taps (reach the highest/lowest tap) and this is mainly because the tests were conducted on average demand days. Typically, demand reduction is required on high demand days and higher demands will prevent transformers operating at last tap during voltage reduction. The other issue related to tap changers is time taken to change taps by different transformers within a zone substation. This causes out-of-step taps among transformers within same zone substation and would not deliver the expected voltage reduction. Further, some of the voltage regulation relays (eg. A. Eberle) prevent manual adjustment of taps without additional switching and intervention when taps are out of step.

⁸ Reliability and Emergency Reserve Trader



Based on the test results, the average voltage sensitivity of demand at participated zone substations is estimated to be 69% or in other words, 1% reduction in voltage is expected to result in 0.69% reduction in active power demand on average. The voltage sensitivity of demand is directly related to the characteristics of the connected load at the time of the voltage reduction. Constant power, constant current and constant impedance loads will react to the voltage reduction in completely different ways. Given the type of loads connected to the network can change over time depending on the season (winter/summer) and time of the day, the demand response to voltage reduction can vary from time to time.

Only one voltage complaint that was directly related to the voltage reductions tests was received from an HV customer. Investigation revealed that network voltages were well within the regulatory limits at that time and the customer under-voltage alarm at their premises was set too high. No LV voltage complaints were received and the voltage dashboard indicated that LV voltage profiles at participated zone substations were within the regulatory limits.

A summary of the average voltage sensitivity of demand is presented in Table 4-1.

Table 4-1: Voltage sensitivity of demand at participated zone substations

Zone substation	Average voltage sensitivity of active power demand	Observed range
BR	64%	86% - 42%
BW	NA	NA
CDA	81%	128% - 30%
CFD	63%	108% - 38%
CRM	57%	111% - 36%
DMA	82%	109% - 53%
DN	65%	86% - 43%
DVY	49%	70% - 23%
EB	103%	144% - 75%
EW	46%	75% - 21%
KBH	67%	105% - 44%
LD	55%	85% - 18%
LWN	52%	117% - 22%
M	65%	73% - 55%
MR	98%	152% - 23%
MTN	71%	95% - 54%
NB	66%	101% - 33%
RBD	89%	108% - 45%



SH	NA	NA
STO	83%	110% - 50%
<i>Network weighted average</i>	69%	



4.1. Background

The testing includes several components such as:

- review of the existing emergency voltage set points and controllability;
- review of the NCC dashboards and Group Functions;
- review of the voltage dashboard; and
- field testing.

Field testings were conducted on three different days.

- Tuesday, 14 November 2017
 - Apply emergency set point 1 at 10 00 and revoke at 14 00
 - Apply emergency set point 1 at 16 00 and revoke at 20 00
- Monday, 20 November 2017
 - Apply emergency set point 2 at 10 00 and revoke at 14 00
 - Apply emergency set point 2 at 16 00 and revoke at 20 00
- Friday, 01 December 2017 (AEMO test 1)
 - Apply emergency set point 2 at 13 00 and revoke at 15 00

This report presents the findings of the reviews and results of the field tests.

4.2. Findings and results

4.2.1. Review of existing emergency voltage settings

The preliminary review of the existing settings revealed that out of 47 UE zone substations, 20 zone substations had SCADA controllable emergency voltage set points. Out of that 13 zone substations have -2% as set point 1 and -4% as set point 2, which are legacy settings. Seven zone substations have -3% as set point 1 and -5% as set point 2, which are compliant with the present UE standard. One zone substation, Keysborough (KBH) has -5% as set point 1 and -7% as set point 2. This is an error in design as the settings were calculated based on the nominal voltage not on float voltage. This needs to be fixed moving forward, however this is not considered as critical at this point in time. The SCADA Group Function lists were updated appropriately to accommodate KBH by including KBH set point 1 to both Emergency 1 and Emergency 2 lists. By doing that we will use -5% voltage reduction at KBH under both cases and -7% will not be used in practice.

It was noticed that emergency settings at Burwood (BW) and Surrey Hill (SH) zone substations were not properly applied and configured. Therefore, arrangements have been made to fix these issues.

Further, Notting Hill (NO), Springvale (SV) and Springvale West (SVW) zone substations are capable of SCADA ready emergency voltage reduction. Therefore, arrangements were made to apply emergency voltage settings at SV and SVW zone substations and configure all three zone substations in SCADA. Changes required at Oakleigh (OAK) was considered to be complex will be addressed as part of the DVMS rollout. Therefore, OAK is left out from emergency voltage reduction.

The proposed changes were actioned, and following these tests we now we have 23 zone substations in total that are ready for SCADA controlled emergency voltage reduction. The list of those substations and relevant emergency voltage set points are presented in Table 4-2.



Table 4-2: List of zone substations that are ready for SCADA controlled emergency voltage reduction

Zone substation	Emergency set point 1	Emergency set point 2
BR	-3%	-5%
BW	-2%	-4%
CDA	-3%	-5%
CFD	-2%	-4%
CRM	-2%	-4%
DMA	-2%	-4%
DN	-2%	-4%
DVY	-3%	-5%
EB	-2%	-4%
EW	-3%	-5%
KBH	-5%	-7%
LD	-3%	-5%
LWN	-2%	-4%
M	-2%	-4%
MR	-2%	-4%
MTN	-2%	-4%
NB	-2%	-4%
NO	-3%	-5%
RBD	-2%	-4%
SH	-2%	-4%
STO	-3%	-5%
SV	-3%	-5%
SVW	-3%	-5%

Legacy emergency set points, -2% and -4%, are considered to be too conservative. Therefore, it is recommended to update all the emergency setting to the UE standard of -3% and -5%. However, given the cost associated with these changes, it is recommended to implement them opportunistically as we progressively replace the relays at each zone substation as part of the DVMS rollout.



4.2.2. Review of dashboards and SCADA Group Functions

NCC dashboards are capable of visualising and controlling emergency voltage set points at the 23 zone substations listed above in Table 4-2. NCC is comfortable with the functionality.

The voltage dashboard can be used to identify the end customer voltage profiles at the zone substations that participate in the emergency voltage reduction. The dashboard works as expected and Network Analytics Team developed a new tool to monitor the voltage profiles and generate an automatic email whenever a more than 1% of customers are outside the regulatory voltage limits.

The original SCADA Group Functions for emergency voltage reduction had few issues as they have not been reviewed for a while. Emergency 1 and Emergency 2 Group Functions are reviewed and updated as part of this assessment to include the 23 zone substations that are ready for SCADA controlled emergency voltage reduction. The following updates were made to the original Group Functions.

- BH was removed from group 1 and 2
- CDA was added to group 1 and 2
- CFD was added to group 1 (It already was in EVC group 2)
- DMA was added to group 1 and 2
- EW was added to group 1 and 2
- NB Trans #2 was added to group 1 and 2
- NO was added to group 1 and 2
- STO was added to group 1 and 2
- SV was added to group 1 and 2
- SVW was added to group 1 and 2

A copy of the updated Group Functions is presented in Table 4-3.

Table 4-3: SCADA Group Functions for emergency voltage reduction

Emergency Voltage Reduction Stage 1	Emergency Voltage Reduction Stage 2
BR #1 66/11kV Trans OLTC Emergency Stage 1 Enable	BR #1 66/11kV Trans OLTC Emergency Stage 2 Enable
BR #2 66/11kV Trans OLTC Emergency Stage 1 Enable	BR #2 66/11kV Trans OLTC Emergency Stage 2 Enable
BW #1 22/11kV Trans OLTC Emergency Stage 1 Enable	BW #1 22/11kV Trans OLTC Emergency Stage 2 Enable
BW #2 22/11kV Trans OLTC Emergency Stage 1 Enable	BW #2 22/11kV Trans OLTC Emergency Stage 2 Enable
BW #3 22/11kV Trans OLTC Emergency Stage 1 Enable	BW #3 22/11kV Trans OLTC Emergency Stage 2 Enable
CDA #1 66/22kV Trans VRR Emergency Stage 1	CDA #1 66/22kV Trans VRR Emergency Stage 2



Enable	Enable
CDA #2 66/22kV Trans VRR Emergency Stage 1 Enable	CDA #2 66/22kV Trans VRR Emergency Stage 2 Enable
CFD #1 66/11kV Trans OLTC Emergency Stage 1 Enable	CFD #1 66/11kV Trans OLTC Emergency Stage 2 Enable
CFD #2 66/11kV Trans OLTC Emergency Stage 1 Enable	CFD #2 66/11kV Trans OLTC Emergency Stage 2 Enable
CRM #1 66/22kV Trans OLTC Emergency Stage 1 Enable	CRM #1 66/22kV Trans OLTC Emergency Stage 2 Enable
CRM #2 66/22kV Trans OLTC Emergency Stage 1 Enable	CRM #2 66/22kV Trans OLTC Emergency Stage 2 Enable
CRM #3 66/22kV Trans OLTC Emergency Stage 1 Enable	CRM #3 66/22kV Trans OLTC Emergency Stage 2 Enable
DMA #1 66/22kV Trans OLTC Emergency Stage 1 Enable	DMA #1 66/22kV Trans OLTC Emergency Stage 2 Enable
DMA #2 66/22kV Trans OLTC Emergency Stage 1 Enable	DMA #2 66/22kV Trans OLTC Emergency Stage 2 Enable
DN #1 66/22kV Trans OLTC Emergency Stage 1 Enable	DN #1 66/22kV Trans OLTC Emergency Stage 2 Enable
DN #2 66/22kV Trans OLTC Emergency Stage 1 Enable	DN #2 66/22kV Trans OLTC Emergency Stage 2 Enable
DN #3 66/22kV Trans OLTC Emergency Stage 1 Enable	DN #3 66/22kV Trans OLTC Emergency Stage 2 Enable
DVY #1 66/22kV Trans OLTC Emergency Stage 1 Enable	DVY #1 66/22kV Trans OLTC Emergency Stage 2 Enable
DVY #2 66/22kV Trans OLTC Emergency Stage 1 Enable	DVY #2 66/22kV Trans OLTC Emergency Stage 2 Enable
DVY #3 66/22kV Trans OLTC Emergency Stage 1 Enable	DVY #3 66/22kV Trans OLTC Emergency Stage 2 Enable
EB #1 66/22kV Trans OLTC Emergency Stage 1 Enable	EB #1 66/22kV Trans OLTC Emergency Stage 2 Enable
EB #2 66/22kV Trans OLTC Emergency Stage 1 Enable	EB #2 66/22kV Trans OLTC Emergency Stage 2 Enable
EB #3 66/22kV Trans OLTC Emergency Stage 1 Enable	EB #3 66/22kV Trans OLTC Emergency Stage 2 Enable
EW #1 66/11kV Trans OLTC Emergency Stage 1 Enable	EW #1 66/11kV Trans OLTC Emergency Stage 2 Enable
EW #2 66/11kV Trans OLTC Emergency Stage 1	EW #2 66/11kV Trans OLTC Emergency Stage 2



Enable	Enable
KBH #3 66/22kV Trans OLTC Emergency Stage 1 Enable	KBH #3 66/22kV Trans OLTC Emergency Stage 1 Enable
LD #1 66/22kV Trans OLTC Emergency Stage 1 Enable	LD #1 66/22kV Trans OLTC Emergency Stage 2 Enable
LD #2 66/22kV Trans OLTC Emergency Stage 1 Enable	LD #2 66/22kV Trans OLTC Emergency Stage 2 Enable
LD #3 66/22kV Trans OLTC Emergency Stage 1 Enable	LD #3 66/22kV Trans OLTC Emergency Stage 2 Enable
LWN #2 66/22kV Trans OLTC Emergency Stage 1 Enable	LWN #2 66/22kV Trans OLTC Emergency Stage 2 Enable
LWN #3 66/22kV Trans OLTC Emergency Stage 1 Enable	LWN #3 66/22kV Trans OLTC Emergency Stage 2 Enable
M #1 66/11kV Trans OLTC Emergency Stage 1 Enable	M #1 66/11kV Trans OLTC Emergency Stage 2 Enable
M #2 66/11kV Trans OLTC Emergency Stage 1 Enable	M #2 66/11kV Trans OLTC Emergency Stage 2 Enable
M #3 66/11kV Trans OLTC Emergency Stage 1 Enable	M #3 66/11kV Trans OLTC Emergency Stage 2 Enable
MR #1 66/11kV Trans OLTC Emergency Stage 1 Enable	MR #1 66/11kV Trans OLTC Emergency Stage 2 Enable
MR #2 66/11kV Trans OLTC Emergency Stage 1 Enable	MR #2 66/11kV Trans OLTC Emergency Stage 2 Enable
MR #3 66/11kV Trans OLTC Emergency Stage 1 Enable	MR #3 66/11kV Trans OLTC Emergency Stage 2 Enable
MTN #2 66/22kV Trans OLTC Emergency Stage 1 Enable	MTN #2 66/22kV Trans OLTC Emergency Stage 2 Enable
MTN #3 66/22kV Trans OLTC Emergency Stage 1 Enable	MTN #3 66/22kV Trans OLTC Emergency Stage 2 Enable
NB #2 66/11kV Trans OLTC Emergency Stage 1 Enable	NB #2 66/11kV Trans OLTC Emergency Stage 2 Enable
NB #3 66/11kV Trans OLTC Emergency Stage 1 Enable	NB #3 66/11kV Trans OLTC Emergency Stage 2 Enable
NO #1 66/22kV Trans OLTC Emergency Stage 1 Enable	NO #1 66/22kV Trans OLTC Emergency Stage 2 Enable
NO #2 66/22kV Trans OLTC Emergency Stage 1 Enable	NO #2 66/22kV Trans OLTC Emergency Stage 2 Enable
NO #3 66/22kV Trans OLTC Emergency Stage 1 Enable	NO #3 66/22kV Trans OLTC Emergency Stage 2 Enable
RBD #1 66/22kV Trans OLTC Emergency Stage 1	RBD #1 66/22kV Trans OLTC Emergency Stage 2



Enable	Enable
RBD #2 66/22kV Trans OLTC Emergency Stage 1 Enable	RBD #2 66/22kV Trans OLTC Emergency Stage 2 Enable
SH #2 22/6.6kV Trans OLTC Emergency Stage 1 Enable	SH #2 22/6.6kV Trans OLTC Emergency Stage 2 Enable
SH #3 22/6.6kV Trans OLTC Emergency Stage 1 Enable	SH #3 22/6.6kV Trans OLTC Emergency Stage 2 Enable
STO #1 66/22kV Trans OLTC Emergency Stage 1 Enable	STO #1 66/22kV Trans OLTC Emergency Stage 2 Enable
STO #2 66/22kV Trans OLTC Emergency Stage 1 Enable	STO #2 66/22kV Trans OLTC Emergency Stage 2 Enable
SV #2 66/22kV Trans OLTC Emergency Stage 1 Enable	SV #2 66/22kV Trans OLTC Emergency Stage 2 Enable
SV #3 66/22kV Trans OLTC Emergency Stage 1 Enable	SV #3 66/22kV Trans OLTC Emergency Stage 2 Enable
SVW #4 66/22kV Trans OLTC Emergency Stage 1 Enable	SVW #4 66/22kV Trans OLTC Emergency Stage 2 Enable
SVW #5 66/22kV Trans OLTC Emergency Stage 1 Enable	SVW #5 66/22kV Trans OLTC Emergency Stage 2 Enable

4.2.3. Field test results

4.2.3.1 Test 1: 14/11/2017 (10 00-14 00 and 16 00-20 00)

During the first test on 14/11/2017, emergency set point 1 was armed using the Group Function. BR did not participate at 10 00 due to RTU issue and subsequently been fixed. BW and SH did not participate as they are not properly configured for emergency voltage reduction. Taps at participating zone substations responded within 9 minutes.

However, -2% set point is too small and similar to the normal dead band of tap changers. Therefore, 11 participated zone substations that have -2% emergency voltage set point 1, responded by adjusting only one tap. Therefore, we could not observe any noticeable demand response at those zone substations due to the size of the natural variability of the demand and the resolution of the available metering. Five zone substations that have -3% emergency voltage set point 1 showed some response and KBH, which has -5% emergency voltage set point 1, showed a reasonable response. Overall, a noticeable demand change could not be observed at a total UE level. Therefore, it is concluded that the existing emergency set point 1 has limited practical use and we decided to use the emergency set point 2 for the remaining tests. Data from this test was not used for any further analysis.

4.2.3.2 Test 2: 20/11/2017 (10 00-14 00 and 16 00-20 00)

During the second test on 20/11/2017, emergency set point 2 was armed using the Group Function. DVY and M did not participate at 10 00 and 14 00 due to RTU issue and tap changer issues respectively. BR results at 14 00 was excluded from further assessment due to a network abnormality. LD results at 16 00 was excluded from further assessment due to strange load behaviour (possibly switching of a large load simultaneous to the voltage reduction test) and LD did not participate at 20 00 due to tap changer issues. Similarly LWN did not participate at 20 00 due to tap changer issues. BW and SH did not participate as they are not properly configured for emergency voltage reduction.



Taps at participating zone substations responded within 8 minutes.

This test included four points in time that we changed the voltage float settings. At 10 00 and 16 00, the float voltage at participating zone substations was dropped and at 14 00 and 20 00, the voltages were restored. The demand responses at those specific times were further analysed and presented later in this report.

4.2.3.3 Test 3: 01/12/2017 (13 00-15 00)

This third test was initiated by AEMO as part of the Reliability and Emergency Reserve Trader (RERT) agreement. During this test on 01/12/2017, emergency set point 2 was armed using the Group Function. CRM did not participate at 15 00 due to tap changer issues. BW and SH did not participate as they are not properly configured for emergency voltage reduction.

Taps at participating zone substations responded within 7 minutes.

This test included two points in time that we changed the voltage. Just before 13 00, the float voltage at participating zone substations were dropped and just after 15 00, the voltages were restored. The demand responses at those specific times were further analysed and presented later in this report.

4.2.3.4 Quantification of demand response

The network load at any given time is a combination of constant power, constant current, constant impedance and any number of variations of those text-book load types. In order to explain and quantify the response of demand to change in voltage, the well-known characteristics of the text-book load types are greatly helpful.

For ideal constant power loads, when voltage drops the current increases by the same amount to maintain the same power output. For ideal constant current loads, the current remains the same irrespective of the change in voltage and as a result the output power varies depending on the variation in voltage. For ideal constant impedance loads, change in current follows the change in voltage and as a result the output power changes by the square of the voltage change. That means for ideal constant power, constant current and constant impedance loads, for small changes in voltages, a 1% change in voltage will result in 0%, 1% and 2% change in active power, respectively.

In order to assess the demand response during the voltage reduction tests, these known characteristics were mapped on to a spectrum and compared against the voltage, current and active power demand behaviour at each zone substation. The response spectrum used for this assessment is summarised in Table 4-4.

Table 4-4: Demand sensitivity spectrum

Sensitivity index %P/%V	Change in current	Change in demand
0.00	Current increase $\Delta I > 0$	$\Delta P = 0$
0.25		$ \Delta P < \Delta I $
0.50		$ \Delta P = \Delta I $
0.75		$ \Delta P > \Delta I $
1.00	$\Delta I = 0$	$\Delta I = 0$
1.25	Current decreases $\Delta I < 0$	$ \Delta P > \Delta I $
1.50		$ \Delta P = \Delta I $

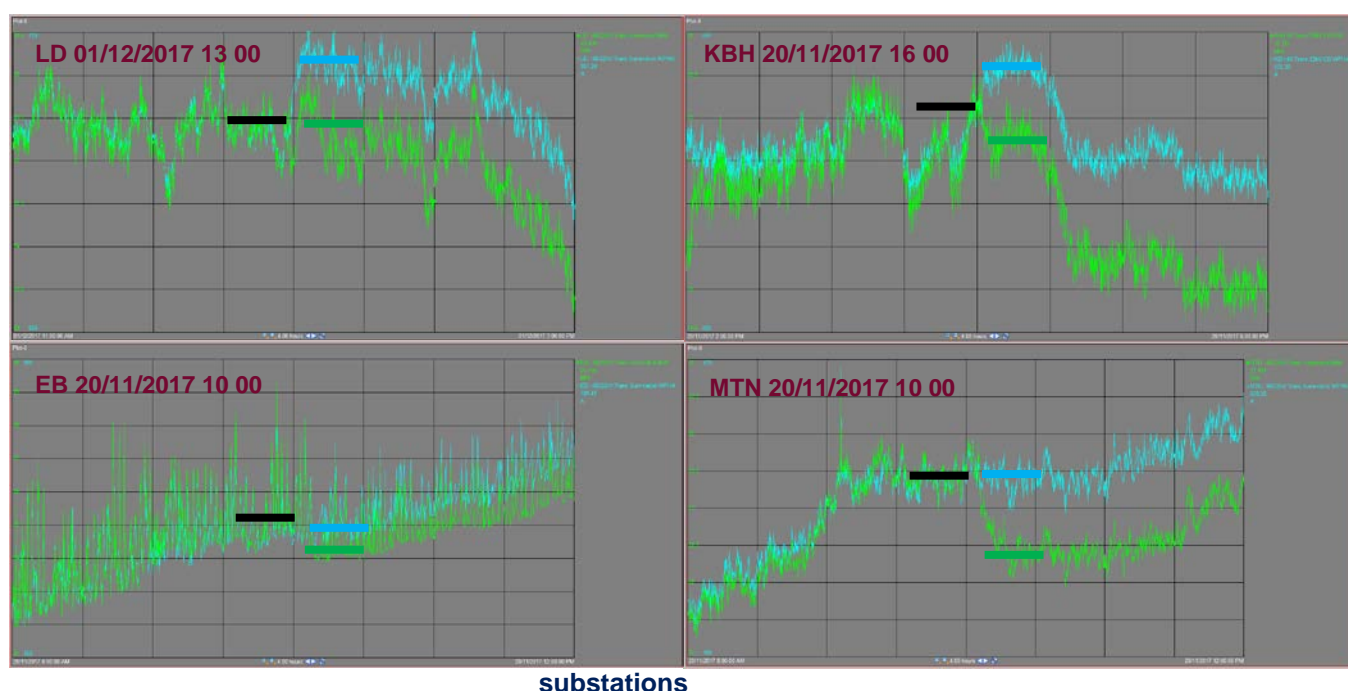


1.75		$ \Delta P \gg \Delta I $
2.00		$ \Delta P \gg \gg \Delta I $

The voltage sensitivity of demand (sensitivity index) is calculated by dividing the percentage change in active power demand by percentage change in voltage at each instance.

The graphical view of the demand and current characteristics at few selected zone substations is presented in Figure 4-1. LD 01/12/2017 13 00 trace indicates a situation where load remains more or less the same while current increase in response to reduction in voltage. The estimated voltage sensitivity of demand at this instance is 0.18, which is close to constant power load. EB 20/11/2017 10 00 trace indicates a situation where both load and current drop in response to reduction in voltage and demand drops more than current. The estimated voltage sensitivity of demand at this instance is 1.44, which is towards the constant impedance load. MTN 20/11/2017 10 00 trace indicates a situation where current remains more or less the same while demand drops in response to reduction in voltage. The estimated voltage sensitivity of demand at this instance is 0.95, which is close to constant current load. KBH 20/11/2017 16 00 trace indicates a situation where current increases while demand drops in response to reduction in voltage. The magnitudes of change in both demand and current are more or less similar. The estimated voltage sensitivity of demand at this instance is 0.53.

Figure 4-1: Demand (Green) and Current (light Blue) characteristics at selected zone



All the demand and current traces at the participated zone substations are presented in Appendix A.

4.2.3.5 Summary of voltage sensitivity of demand

Similar to the method discussed above, the voltage sensitivity of demand at each participating zone substation was estimated. The results are summarised in Table 4-5.



Table 4-5: Summary of voltage sensitivity of demand at participated zone substations

ZSS	20 Nov 2017								01 Dec 2017				Average	
	10 00		14 00		16 00		20 00		13 00		15 00			
	ΔP (MW)	VSOL (%)	ΔP (MW)	VSOL (%)	ΔP (MW)	VSOL (%)	ΔP (MW)	VSOL (%)	ΔP (MW)	VSOL (%)	ΔP (MW)	VSOL (%)	ΔP (MW)	VSOL (%)
BR	0.39	86%	NA		0.33	65%	0.22	42%	0.31	58%	0.31	70%	0.31	64%
BW	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
CDA	1.47	128%	0.31	30%	1.00	68%	0.27	32%	1.67	118%	0.73	73%	0.91	81%
CFD	0.50	67%	0.36	38%	0.73	65%	0.64	56%	0.67	71%	0.44	108%	0.56	63%
CRM	0.50	67%	0.33	36%	0.44	42%	0.70	111%	0.89	52%	NA	NA	0.57	57%
DMA	0.24	82%	0.50	109%	0.33	57%	0.11	53%	0.39	94%	0.20	107%	0.29	82%
DN	1.65	80%	0.79	44%	1.07	43%	1.13	84%	1.13	72%	1.23	86%	1.16	65%
DVY	NA	NA	NA	NA	2.14	67%	0.40	23%	1.23	37%	1.00	70%	1.19	49%
EB	1.33	144%	0.80	75%	1.44	110%	1.23	103%	0.69	92%	0.92	95%	1.07	103%
EW	0.09	21%	0.24	44%	0.19	44%	0.14	38%	0.31	75%	0.20	71%	0.19	46%
KBH	0.42	51%	0.96	105%	0.53	53%	0.35	44%	0.63	71%	0.45	78%	0.56	67%
LD	0.72	85%	0.82	60%	NA	NA	NA	NA	0.23	18%	0.63	71%	0.60	55%
LWN	0.69	117%	0.25	32%	0.45	48%	0.53	55%	0.33	51%	0.14	22%	0.40	52%
M	NA	NA	NA	NA	0.40	72%	NA	NA	0.40	55%	0.31	73%	0.37	65%
MR	0.77	98%	0.81	85%	0.25	23%	1.07	107%	1.62	133%	1.15	152%	0.94	98%
MTN	1.12	95%	0.90	91%	0.67	54%	0.62	56%	0.64	59%	0.73	75%	0.78	71%
NB	0.22	33%	0.30	35%	0.73	76%	0.53	76%	0.73	73%	0.78	101%	0.55	66%
RBD	0.47	98%	0.60	108%	0.46	96%	0.61	93%	0.53	93%	0.23	45%	0.48	89%
SH	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
STO	0.40	82%	0.25	50%	0.63	95%	0.30	66%	0.30	94%	0.45	110%	0.39	83%
Total Response		87%		60%		62%		64%		67%		83%		69%

4.2.3.6 Customer complaints during tests

Only one voltage complaint directly related to the voltage reduction tests was reported. During the 20/11/2017 tests, an HV customer complained about activating their under-voltage alarms. However, their voltage was well within the regulatory limits and appeared to be their under-voltage alarm settings are too conservative.

LV voltage profiles of participated zone substations were within the regulatory limits as observed on voltage dashboard. No LV voltage complaints related to the tests was received.

4.2.3.7 Deterioration of impact of voltage reduction

It is expected that the impact of voltage reduction would deteriorate overtime as the diversity across loads are converged to a new equilibrium. However, the tests we conducted were not suitable to verify this hypothesis as the network load compositions were changing over time. For example, CDA load was observed to be changing from majority of constant current and constant impedance (sensitivity index of 1.28) to majority of constant power (sensitivity index of 0.30) between 10 00 and 14 00 on 20/11/2017. Therefore, a controlled test (maintaining the same load composition over time) is required to assess and quantify this aspect.

4.3. Learnings

Base on the findings of the tests conducted, the following recommendations are made.



- The impact of the existing emergency set point 1 could not be quantified. Therefore, emergency set point 2 should directly be used, not staged application of set points, when voltage reduction is used for demand management.
- The legacy -2% and -4% emergency set points at 13 zone substations should progressively be updated to match with the current UE standard of -3% and -5%. These updates can be implemented as part of the DVMS rollout.
- Once all the emergency set points are updated to the current UE standard, both emergency set point can practically be used for demand management.
- For RERT obligations, the Group Function should run 10 minutes before the time specified by AEMO to allow sufficient time to dispatch SCADA commands. Running the Group Function earlier than that is considered to be detrimental as that can affect the baseline calculations, which is used to verify the delivery of demand reductions.
- Even though we have not received any voltage complaints, Call Centre and other major stakeholders should be informed before any planned, including RERT, dispatch of voltage reduction.
- The sensitivity indices presented in this report should only be used for summer applications.
- The sensitivity indices should regularly be updated based on the results of future tests and actual demand management exercise to improve the robustness of the values.
- Given the network load composition is different from season to season, the sensitivity indices calculated during these tests should not be used for winter applications. A similar tests should be conducted during winter to estimate the indices related to that season.



5. Glossary of Terms

The following terms are referenced within this document:

Term	Description
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
CDA	Clarinda Zone Substation
DR	Disaster Recovery
DVMS	Dynamic Voltage Regulation System
HT	Heatherton Zone Substation
HV	High Voltage
I/O	Input and Output
IU	Interface Unit
LV	Low Voltage
NAP	Network Analytics Platform
NCC	Network Control Centre
OLTC	On-Load Tap Changer
OT	Operating Technology
RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SDVMA	SCADA Dynamic Voltage Management Application
SVTS	Springvale Terminal Station
UE	United Energy
VRR	Voltage Regulating Relay